ALTERNATIVE MARKET STRUCTURES FOR RETAIL COMPETITION

A REPORT ON MARKET STRUCTURE TO THE MISSOURI PUBLIC SERVICE COMMISSION=S TASK FORCE ON RETAIL COMPETITION

FROM THE TASK FORCE WORKING GROUP ON MARKET STRUCTURE AND MARKET POWER

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REPORT SUMMARY

This report on alternative market structures for retail competition represents the efforts of the Market Structure and Market Power working group of the Missouri Public Service Commission=s (MoPSC=s) Task Force on Retail Competition. The format of this report is that the first chapter sets out the structural changes that the working group believed would be common to any of the alternative proposals for market structure. The subsequent chapters organize each proposed market structure into four major sections: Description of the Structure; Potential Issues; Potential Structural Impacts on Utilities; and Potential Impacts on Consumers. A comparative summary of the three proposed structures is presented below, including definitions of terms that are used throughout the report.

A. DESCRIPTION OF THE STRUCTURE

This section includes a brief description of the market structure, followed by a detailed description of how the structure will work in regard to the various business units involved. These business units include: generation; transmission; distribution; retail electric provider; and customer services. The following gives the definitions for each of these business units.

Utility Business Units refer to the separate business unit functions of the vertically integrated utility.

(1) ***Generation*** is the function of producing electricity and delivering that power to the interconnected transmission grid at the required voltage level.

(2) ***Transmission*** is the function of transporting electricity at high voltage from the generators to the local distribution systems.

(3) ***Distribution*** is the function of delivering electricity at low voltage from the transmission system to the end-use consumer.

(4) ***Customer Service*** is the function of metering and billing the end-use consumer.

- The word ***customer*** is used in the context of a specific business unit providing services to an end-use consumer.

- The word ***consumer*** is used in the more general context of an end-user of electricity that can be served by any number of alternative competitors.

Business Entities refer to firms that will provide the various disaggregated utility functions, as well as new functions within a competitive market.

(1) ***Generator (GENCO)*** is the firm that produces electricity for sale in a competitive market for electricity. These firms might be what is currently a part of the vertically integrated utility, or might be completely independent of any other utility functions.

(2) ***Transmission Owning Utility (TOU)*** is the firm that owns transmission facilities. Currently, transmission facilities are owned by utility companies.

(3) ***Independent System Operator (ISO)*** is an entity that operates a regional network of transmission facilities, but does not own those facilities. It is independent of the utilities in the sense that the utilities are not able to control the operations of the ISO.

(4) ***Local Distribution Utility (LDU)*** is the utility business unit that provides distribution wires services to end-use consumers, may provide customer services and may provide certain limited generation services. The LDU=s services will be provided to end-use consumers at regulated rates.

(5) ***Retail Electric Provider (REP)*** is an entity that sells electricity to end-use consumers, buys or procures electricity from generators, and arranges for the transmission of electricity with either the TOUs or the ISOs. In effect, REPs are the retailers of electricity. In certain market structures, the REP may also provide customer services. If a vertically integrated utility chooses to be an REP, that function will be provided by a separate entity from the LDU.

(6) ***Poolco and/or Power Exchange (PX)*** are entities that operate a region-wide, competitive market for electricity generation. The poolco has responsibility and authority for the commercial terms for all transactions of electricity that take place within the region. The PX has responsibility and authority for developing and maintaining a spot market for electricity.

Common Structural Changes involved in the restructured electric industry will likely include a regional transmission system operated by an ISO that connects the distribution systems of the current utilities which will become the LDUs. Both transmission and distribution will continue to be regulated: transmission by the FERC; and distribution by the relevant state or local regulatory authority. The Task Force assumes that generation will eventually be provided competitively. However, customer services such as metering and billing may either be provided competitively or continue to be provided by the LDU on a regulated basis.

Transmission will likely evolve to where the TOUs will have turned over the operational control of their transmission assets to a regional ISO that will operate those facilities as a regionally integrated network. The ISO will have a region-wide transmission tariff that is regulated by the FERC. The ISOs will maintain the reliability of the transmission network, following regional reliability council standards and procedures. A major function of the ISO will be to approve the scheduling of electricity in such a way as to maintain the security of the wires and provide a level playing field for commercial opportunities to buy and sell power.

The distribution function involving ownership, planning, construction, maintenance and storm restoration of the local distribution system will be provided as a regulated service by the LDU. However, metering, meter reading and billing could be provided on a competitive basis irrespective of the structure used to competitively provide generation services. There is agreement that the LDU will not provide generation services on a competitive basis. If the utility stays in the generation business, that part of its business (its function as a GENCO or REP) must be functionally separate from the regulated part of its business. In some instances, the LDU may be allowed to provide generation services as an agent that simply passes through the costs of generation that have competitively been determined in a market in which the LDU is not acting as a commercial agent that can profit or lose from its actions.

Alternative Market Structures proposed for competitive generation markets in this report include the following:

(1) ***Direct Access*** is a structure in which REPs directly negotiate with consumers to be their REP, and make standard offers of service available for various defined classes of service. The LDU provides distribution services and perhaps customer service, but does not provide electric energy services. The REP must schedule the supply of electricity with the ISO and/or individual TOUs if ISOs are not operational throughout the state. The REPs will also serve high-cost/high-risk consumers and will be assigned to serve consumers that opt not to choose a REP.

(2) ***Poolco*** is a structure in which generation competition takes place at the wholesale level as generators and power marketers sell electricity to a common pool. For all electricity sold at retail, the poolco purchases electricity on a competitive bid basis, and resells electricity to the LDUs at cost. The LDUs provide electric service to end-use consumers through rates set by the appropriate regulatory agency. These rates include a pass through of the electric energy costs charged to the LDU by the poolco.

(3) ***Hybrid*** is a combination structure in which both REPs and a PX are active in the commercial sales of electricity. The REPs will function in the same fashion as described by the direct access structure. However, the PX has no authority or responsibility regarding electricity supplied by REPs for end-use consumers. The LDU does not supply electricity competitively, but may provide electricity which it purchases from the PX to supply the requirements of high-cost/high-risk consumers and consumers that opt not to choose a REP.

B. POTENTIAL ISSUES

This section includes a list of issues that must be resolved in order for the proposed market structure to function effectively.

Irrespective of the market structure, a properly designed and implemented ISO should alleviate vertical market power problems related to non-discriminatory access to the transmission system. ISO issues, such as governance, transmission pricing and who will build new transmission facilities, will be addressed at the federal level. ISOs will play an integral part in the settlement

process involving payments for differences between scheduled and actual generation, as well as between forecasted and actual usage. It is also likely that competitive supply of generation will require new standards of generation reliability to be addressed both at the federal and state level.

State and local regulatory authorities will need to address other market power issues, particularly those related to restrictions on import capability into local markets. To the extent must-run generation plays a role in meeting local requirements for electricity, state or local regulatory authorities will need to determine the appropriate compensation. Another major issue for the state legislature is whether to allow out-of-state generation to participate in the competitive generation markets in Missouri if generators in Missouri are not allowed to participate in competition for retail loads in that other state. In addition, the state legislature will need to determine whether municipals and cooperatives will have an option to not participate in retail competition for electric generation. There is the legal question as to whether existing wholesale contracts can be abrogated if the state moves to a new system of retail competition. There is also a regulatory question as to whether utilities should be allowed to sell any or all of its generating facilities without prior regulatory approval.

The need to change tax laws which relate to taxes on utilities and taxes on end-use consumers which are collected by utilities is a critical issue because it affects both the overall level of tax receipts and the promotion of a level playing field for all competitors. Options for renewable energy sources that are not economic in a competitive electricity industry and where consumers do not (or cannot) choose to pay extra for power from such sources may need to be considered both with respect to requiring Green Power options being made available and with respect to state funding for development.

Table 1 includes a list of potential issues with cross references to the applicability of each issue for each market structure.

TABLE 1
POTENTIAL ISSUES BY MARKET STRUCTURE

Potential Issues List	Direct Access	Poolco	Hybrid
Infrastructure Needs			
a) Load Forecasts	REPs	LDUs	REPs/LDUs
b) Scheduling Supply with ISO	REPs	Poolco	REPs/LDUs
c) Ancillary Services	ISO	ISO	ISO
d) Balancing	ISO	ISO	ISO
e) Settlements	REPs	LDUs	REPs/LDUs/PX
f) Hourly Metering Requirements	ISO	Poolco	ISO/PX
g) Data Access for Billing & Forecasting	REPs	CFDs	REPs
Certification of New Participants	REPs	CFD Dealers	REPs
Setting Generation Supply Reliability Requirements	ISO	ISO/Poolco	ISO
Purchased Power Cost Recovery for LDUs		PGA or Other Mechanisms	
Standard Rates & Rate Design			
1) LDUs		Flexibility	Flexibility
2) REPs	Standard Offer		Standard Offer
Customer Service Unbundling			
1) Metering by entity other than LDU	LDUs & REPs	Future Option	LDUs & REPs
2) Billing by entity other than LDU	LDUs & REPs	Future Option	LDUs & REPs
Municipal/Cooperatives: Opt In / Opt Out	State Legislature	State Legislature	State Legislature
Affiliate Transaction Rules & Standards of Conduct	GENCO	GENCO	GENCO
Relationship of Regulated Entities (T&D) to	REP	Outstate REP	REP
Establish Rules for Bidding Generation		Contracts Spot Price	Spot Price
Management & Governance of Poolco / PX			
1) Legislative Approval		State	State

2) Regulatory Oversight		FERC	FERC
Repeal of Anti Flip-Flop Law	Yes	No	Yes

C. POTENTIAL STRUCTURAL IMPACTS ON UTILITIES

This section includes a list of changes (impacts) that will likely need to be made to the existing structure of the vertically integrated utility companies were the proposed market structure to be implemented.

Irrespective of the market structure, retail competition will require functionally separating generation from the other business functions of the utility. The remaining LDU will provide distribution and perhaps customer services, but will no longer have the obligation to provide generation services to its customers. Municipals, because of the tax free status for their bonds, may face Aprivate use restrictions@ that would preclude their participation in retail competition. Continuation of utility funded conservation programs that are not profitable would require an additional distribution wires charge or alternatively a franchise fee levied on all REPs.

Table 2 includes a list of potential structural issues with cross references to the applicability of each issue for each market structure.

TABLE 2
POTENTIAL STRUCTURAL IMPACTS ON UTILITIES
BY MARKET STRUCTURE

Potential Structural Impacts List	Direct Access	Poolco	Hybrid
Obligation to Serve by Utility	No	No	No
Company Restructuring	Yes	Yes	Yes
Standards of Conduct	Yes	Yes	Yes
Rate and Bill Unbundling			
a) Distribution Rates	LDU	LDU	LDU
b) Transmission Rates	ISO	ISO	ISO
c) Regulated Generation Rates		LDU	LDU
d) Regulated Customer Service Rates	LDU	LDU	LDU
e) Separate Components on Customer=s Bill	Yes	Yes	Yes

Upgrades to Customer Information Systems	Yes	No	Yes

D. POTENTIAL IMPACTS ON CONSUMERS

This section includes a list of changes which end-use consumers are likely to face if the proposed market structure were to be implemented.

Irrespective of the market structure, consumers will see unbundled rates in which the competitively supplied services are separated from those services that remain regulated. Consumers will be faced with the possibility of increasing prices being the mechanism by which a fixed short-run supply of generation is allocated among competitive end uses. Various levels of firmness in supply may also develop as a way for consumers to have different levels of generation reliability. In this new competitive supply of generation there will likely be greater price volatility, which may result in REPs or LDUs offering fixed price alternatives. Consumer education will need to focus on the implications of variable and fixed pricing alternatives. In the short run, while some consumers may see lower prices for electricity, others may face higher prices. The degree to which electric prices differ from regulated levels will, in part, depend on state policy regarding recovery of stranded/transition costs.

Table 3 includes a list of potential impacts on consumers with cross references to the applicability of each impact for each market structure.

TABLE 3
POTENTIAL CONSUMER IMPACTS BY MARKET STRUCTURE

Potential Consumer Impacts List	Direct Access	Poolco	Hybrid
Generation Service Options			
$ Aggregators	Yes		Yes
$ LDU			Yes
$ PX / Poolco		Yes	Yes
$ Other Alternative REPs	Yes		Yes
Metering and Billing Options from REPs	Yes	Not Immediately	Yes
Metering	Option of the REP	Future Option as	Option of the REP
Billing	1 Bill Option	Competitively	1 Bill Option
	from REP or LDU	Offered Services	from LDU or REP
Consumer Education	New Customer	Price Changes	New Customer
	Options, Changes	from Purchased	Options, Changes &
	& Procedures	Power Recovery	Procedures
Sales Practices	Standard Cost		Standard Cost
	Comparison		Comparison
Marketing Costs	Marketing Costs for	Marketing Costs for	Marketing Costs for
	REPs	CFDs	REPs
Generation Reliability	Market Supply	Market Supply	Market Supply
	ISO Penalties	Contract Standards	Contract Standards
Provider of Last Resort	REP	LDUs	LDUs
	Standard Offer	via Poolco	via PX

Assignment of Default Customers	Allocated Among REPs or Bid by REPs	LDUs via Poolco	LDUs via PX
Privacy of Consumer Information	Consumer Permission Required	CFD Consumer Permission Required	Consumer Permission Required

CHAPTER 1
ELECTRIC TRANSMISSION AND DISTRIBUTION STRUCTURES AND OTHER AREAS OF AGREEMENT FOR RETAIL COMPETITION[1]

A. DESCRIPTION OF THE STRUCTURE

The restructured electric industry will likely have a regional transmission system operated by an Independent System Operator (ISO). Distribution service will continue to be provided by the Local Distribution Utilities (LDUs) that are currently operating those systems. Transmission pricing will be regulated by the Federal Energy Regulatory Commission (FERC), and distribution rates will continue to be set by the regulatory authorities that are currently setting those prices.

(1) The Generation Business Unit

In this chapter of the report, the assumption is made that there will be some form of competitive market for generation. Whether this involves a poolco, direct access to alternative Retail Electric Providers (REPs) or a power exchange does not impact the structure and conclusions reached in this chapter regarding the transmission and distribution of electricity. It is therefore assumed in all of the structures that providing the generation of electricity will

[1] This chapter represents a part of the industry restructuring on which the Market Structure and Market Power

no longer be the responsibility of the LDU, but will become a competitively supplied commodity.

One characteristic of all of the proposed competitive market structures for generation is that there will be locational differences in electric prices at times when reliability restrictions on the transmission system prevent the unconstrained flow of electricity. For example, when less expensive generation upstream of a constrained transmission interface must be replaced by more expensive downstream generation, the downstream price for electricity will be higher than the upstream price.

(2) The Transmission Business Unit

Working Group is in agreement.

Transmission will remain a monopoly function. It is likely, although not mandated by the FERC, that Transmission Owning Utilities (TOUs) will turn over operational control of their transmission assets to an ISO.[2] While it is also possible that TOUs may continue to operate and control their transmission systems,[3] the remainder of this section will focus on a description of the role of the ISO functioning within a structure of a fully competitive market for generation.

ISOs are likely to evolve to be at least as large as the existing North American Electric Reliability Council (NERC) regions, if not larger, and provide open, non-discriminatory access to all competitive generators. ISOs will be regulated by the FERC, with pricing for transmission services set by the FERC.

[2] This is not to say that there is a consensus of the working group that an ISO is required in order to have retail competition. This question will be addressed as the working group considers the question of market power.

[3] Until an ISO is created and operational, the transmission functions of the ISO would be performed by the functionally separated transmission business unit of the transmission-owning utility.

Each ISO will have a pool-wide transmission tariff that all users of the transmission system will pay.[4] There may be additional charges for use of parts of the transmission system when those parts of the transmission system are congested.[5] In order to encourage the most efficient scheduling of generation to meet loads, both the pricing and clearing of transmission congestion may be based on the opportunity cost of generation. For example, either firm capacity reservations for transmission (CRTs) or transmission congestion contracts (TCCs) could be used for providing market participants with a firm right to use the transmission grid. When congestion occurs, these firm rights could be traded based on the opportunity costs of various generators and end-use consumers whose actions can clear the congestion. The exact form of the markets for firm transmission rights will be proposed by the ISOs, with final approval by the FERC.

Each ISO will follow NERC and regional council reliability standards and emergency procedure standards as they will be responsible for the short-term reliability of the system. Other key ISO responsibilities will likely include:

- Coordination of the scheduling of generation to meet load (supply and demand);
- Authority to redispatch generation for the purpose of maintaining system integrity or relieving transmission constraints;
- Authority to approve or reject proposed transactions solely based on reliability considerations;
- Authority to curtail transactions only in order to maintain reliability;

[4] This tariff may be either a Apostage-stamp@ (one price), a Alicense plate@ (zonal prices) or a Adistance sensitive@ (megawatt-mile) rate.

[5] Congestion occurs on part of the transmission system when the configuration of generation and load is such that not all transactions can take place without threatening the security of that part of the system.

- Procuring ancillary services[6] for customers who do not provide their own; and
- Providing information on transmission pricing and availability.

Maintenance of the transmission system will likely be performed by the TOUs, but will be scheduled with consent from the ISO. Planning for upgrades and new lines will also be done by the ISO and TOUs. The ISO will likely have the authority over the construction of needed transmission facilities.

(3) The Distribution Business Unit

[6]FERC Order 888 concludes that the following six ancillary services must be included in an open access transmission tariff: (1) Scheduling, System Control and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Source Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve - Spinning Reserve Service; and (6) Operating Reserve - Supplemental Reserve Service.

Distribution will remain a monopoly function. The LDU will retain ownership, planning, construction, maintenance and storm restoration responsibilities. Distribution rates will continue to be set by the appropriate state or local regulatory authority, but may move from the traditional rate-of-return-based regulation to performance-based regulation.[7] Just as today, each incumbent LDU would have the obligation to physically connect each customer in its service area to the distribution system, assuring continued availability of electric service to all customers. Billing for distribution services could be done either by the REP or the LDU.

(4) The Customer Service Business Unit

There is no general agreement within the working group on the structure for the customer service business unit that deals with metering, meter reading and billing customers. It should be kept in mind that this part of the utility business is being treated as functionally separate from the LDU=s provision of distribution services. The point of separation between these functions is at the LDU=s side of the customer=s meter. Whether or not customer services are made competitive is a separate question from which structure should be used to open the generation business to competition. (However, some structures may perform better if customer services are provided competitively).

B. POTENTIAL ISSUES

[7] Performance Based Regulation is a mechanism that attempts to link rewards (generally, profits) to desired results or targets rather than to the LDU=s cost of service. PBR allows LDUs with better performance to earn greater profits.

1. Market Power Problems. Market power is the ability of a particular seller or group of sellers to control the price of electricity in a specific geographic market, and to create and maintain effective barriers to entry into that market.

a) A properly designed and implemented ISO should alleviate **vertical** market power problems that would stem from existing utilities preventing competitors from having comparable use of the transmission system. Because the FERC is wanting to move to market-based pricing for wholesale power, the vertical market power issue related to open access on the transmission system will likely be addressed at the federal level. Other vertical market power questions would be addressed by the state.

b) **Horizontal** market power in generation markets exists when one entity owns a substantial portion of the generating capability in a region, and that region has insufficient import capability to allow a sufficient level of generation alternatives for robust competition.[8] At the retail level, the extent and mitigation (e.g., divestiture - the sale of generation assets by the LDU) of horizontal market power will need to be addressed by the state.

c) Alternative remedies to requiring divestiture of generation will require that the specific situation be analyzed, including transmission upgrades, bidding restrictions, and the introduction of new entrants.

2. ISO-Related Issues. If there is an ISO, then the following transmission related issues will need to be resolved at the federal level.

a) Governance (e.g., interested vs. disinterested board of directors for the ISO)[9];
b) Assignment of responsibilities between the ISO and transmission owners for the planning, operation and maintenance of the transmission system;
c) Authority to order the construction of transmission facilities;[10]

[8] Robust competition exists in a market when any given supplier must price its product based on the prices set by competitors of identical products or products that are close substitutes.

[9] For the interested board there are additional issues related to the balance of representation for the various interested parties.

[10]The FERC has regulatory authority over the ISO, but many states have regulatory authority over the citing of any new transmission facilities.

d) Responsibility to build new transmission facilities;[11]
e) Pricing of transmission; and
f) Funding of the ISO.

The FERC has provided guidance in these areas through its eleven ISO principles,[12] as well as in its orders approving the formation of ISOs.

3. Settlement Process. If there is an ISO, it will have oversight for the settlement process, involving payments for differences between scheduled and actual generation, as well as actual and forecasted usage. If there is not an ISO, then there will need to be some alternative form of clearing house to perform this function.[13]

4. Must-Run Generation Units. The functional need, rates for compensation, and operational control will need to be determined for generation units that must run for system reliability reasons.

5. Reciprocity. Some states are considering allowing out-of-state generators to participate in retail markets only if those generators' home state reciprocate. It will have to be determined whether to restrict the ability of out-of-state generators to participate in Missouri retail markets if the state in which the generator is based does not have retail markets in which Missouri generators can participate. In addition, to the extent that Missouri chooses a market structure that, for reasons other than reciprocity, is not open to all generators, this may limit the ability

[11] This is of particular concern when the TOU in the area needing the additional transmission facilities does not want to build them. Thus, this issue could be restated as: Having the right incentives for building new transmission facilities.

[12] These eleven principles as stated in FERC Order 888 have been reproduced as an appendix to this report.

[13] For example, the functionally separated transmission business unit of the TOUs could preform this function.

of Missouri generators to participate in other states= markets. There may also be federal limitations placed on reciprocity provisions.

6. Municipal and Cooperative Participation. The state legislature needs to determine whether municipal and/or cooperative electric systems will be exempted from retail competition and to what extent the exempted entities that have generation would be allowed to participate in the competitive market for retail load.

7. Standards for Firm Service. The question of potential changes in generation reliability from moving to a competitive supply of electricity will need to be addressed at both the state and federal level. This may involve setting standards for providing what is now called firm service.

8. Treatment of Existing Wholesale Contracts. Regardless of the structure used, the state must decide whether it will attempt to abrogate existing wholesale and/or retail contracts for the purchase and sale of electricity which were negotiated prior to the advent of competition. If the state does attempt to do so, there is a question as to whether that action would be deemed unconstitutional (e.g., in violation of Art. I, Section 10, Clause 1 of the U.S. Constitution, which says that ANo State shall ... pass any ... law impairing the obligation of contracts ... .@)

9. Tax Issues. Absent any change in tax laws, restructuring could have two types of tax impacts: (a) Regardless of the structure used, if competition reduces utility revenues and/or the value of utility assets, there will be a resulting decrease in municipal utility taxes and fees, sales and use taxes and income taxes.

(b) Suppliers without a sufficient Anexus@ to the municipality where electricity is consumed would not be subject to that municipality=s gross receipts tax. This produces two effects:

it would further reduce the level of gross receipts tax revenues; and it would provide a competitive advantage to any supplier who can avoid those gross receipts taxes.[14]

10. Sale of Generating Facilities. In a competitive market for generation the state legislature should determine whether utilities will be free to sell any or all of their generating facilities without regulatory approval. This determination will not come up until market power and stranded cost issues are first addressed.

11. Generation from Renewable Energy Sources. To the extent that renewable energy sources such as wind and solar power are not currently economic and consumers do not (or cannot) choose to pay extra for power from such sources, they would not be available in a competitive market for electricity. There are two issues regarding renewable energy sources that the state legislature may need to consider.

a) Should electricity from renewable energy sources be required as an option available to all end-use consumers - Green Power Option?

b) Should the state support the development of renewable energy sources through programs aimed at specific options that have promise for future development in Missouri?

12. Information on Stranded Costs. One possibility for treatment of stranded costs would involve recovery to shareholders or credits to ratepayers of such costs on the basis of estimated revenues in the competitive market, with an Aafter the fact@ true-up of the actual level of stranded costs. If that procedure is used, then regardless of the market structure utilized, utilities seeking recovery of stranded costs would be required to provide the information necessary to calculate the actual level of their stranded costs.

[14]Under the poolco structure, the problems described under section (b) above are not issues because the LDU retains its nexus to all municipalities within its service area.

C. POTENTIAL STRUCTURAL IMPACTS ON UTILITIES

1. Corporate Restructuring. Generation will be functionally separated from transmission and distribution. To some extent this has already occurred under FERC Orders 888, 888-A, 889 and 889-A. The degree of separation - from simply having a separate division within the existing utility to having a separate subsidiary to selling off the generation assets of the utility - may need to be determined at the state level.[15]

2. Obligation to Serve. With generation open to competition, the incumbent utilities will no longer have the obligation to plan for and build new generation. The obligation of the LDU to serve will be redefined as an obligation to connect customers to the grid and deliver energy at the market price. If the LDU takes on the role as the provider of last resort, then its obligation to serve will be to purchase sufficient generation in a competitive wholesale market to meet the electricity requirements of those customers who opt not to choose or are unable to obtain service from an alternative REP.

3. Municipal Participation in Retail Competition. Congress is considering several pieces of legislation that would change the Aprivate use restrictions@ on tax exempt municipal financing to limit the use of transmission facilities in an ISO, to limit the use of distribution facilities for open access, or to prevent competing for customers outside the municipal>s service area. These proposed additional restrictions, if adopted, would be a deterrent to municipal utilities participating in utility restructuring.[16]

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[15] The working group will consider the issues of the degree of separation in its future discussion of market power.

[16] On January 21, 1998, the Internal Revenue Service issued temporary regulations regarding Aprivate use

restrictions@ on tax exempt debt clarifying that municipally owned utilities can, in certain ways, participate in a deregulated utility market without jeopardizing the tax exempt status of outstanding debt. The regulations are for a three year period and expire February 22, 2001.

4. Potential Loss of Electric Revenues Used for Providing Other Services. The investor-owned utilities, municipals and cooperatives offer various electricity conservation programs which are funded by electricity rate revenues. While REPs may provide conservation services that are profitable, programs that are not profitable may not be offered. In addition, many municipals transfer excess revenues from electricity sales to other municipal purposes in order to provide city services that are not related to electricity use. If these services are to continue, they could be funded either through an additional distribution wires charge or, in the case of direct access, by a franchise fee levied on all REPs. While the distributions wires charge would be subject to state or local regulatory approval, the state legislature may need to approve the setting of a franchise fee.

D. POTENTIAL IMPACTS ON CONSUMERS

1. Unbundled Rates for Transmission and Distribution. With retail competition, and the corporate unbundling of generation, there will also be a parallel rate unbundling for consumers. The unbundling of transmission rates (including ancillary services) will be done at the federal level, under the jurisdiction of the FERC. However, the FERC has allowed the states a role in initially making a determination of which facilities are transmission versus distribution in function.[17] At the retail consumer level, rates for distribution will need to be set out separately.

[17] The FERC has given guidance on this issue in what it calls the seven factor test.

However, in all of the alternative structures that follow, it is possible for end-use consumers to be offered either a bundled rate on a single bill, or an unbundled rate on a single bill.[18]

2. Obligation to Supply Electricity. With the supply of electricity becoming completely a competitive market function, there will no longer be an obligation to supply customers with all the electricity they want at a fixed price. If, in the short run, the supply of generation cannot increase in response to price increases, the limited supply of generation will be allocated by the rising market price to customers that place the highest value on their use of electricity and are willing and able to pay. It is expected that the times when the prices for electricity will be increasing in response to the inability to expand the short-run supply of generation will primarily occur during the peak (highest) hours of demand.

3. Generation Reliability. End-use consumers may see a different level of generation reliability than exists under the current system which uses designed levels of planning reserves for generation. In addition, a variety of level-of-firmness options for accepting different levels of generation reliability will likely need to be made available to end-use consumers.

4. Price Volatility. Competitive markets for generation will likely result in greater volatility in prices paid by REPs or LDUs. Depending on market structure, REPs or LDUs may offer fixed price alternatives to end-use consumers, but consumers will need to understand the implications of variable and fixed price offerings. Consumers will also have the choice of price options including risk management tools.

[18] In the poolco structure, the customer=s bill can be segmented into the various components for purposes of information, but not for the purposes of customer choice.

5. Price Level Changes. Competitive markets for generation will cause prices to vary from the level that would exist if the current market structure was maintained. The speed, magnitude and direction of these changes cannot be precisely predicted. In the short run, some consumers may face lower prices while others may face higher prices. The degree to which prices will vary in the short run from the levels that would exist absent restructuring will depend in part on the policy of recovery of positive and negative stranded costs and/or transition costs.

CHAPTER 2
A DIRECT ACCESS MARKET STRUCTURE [19]

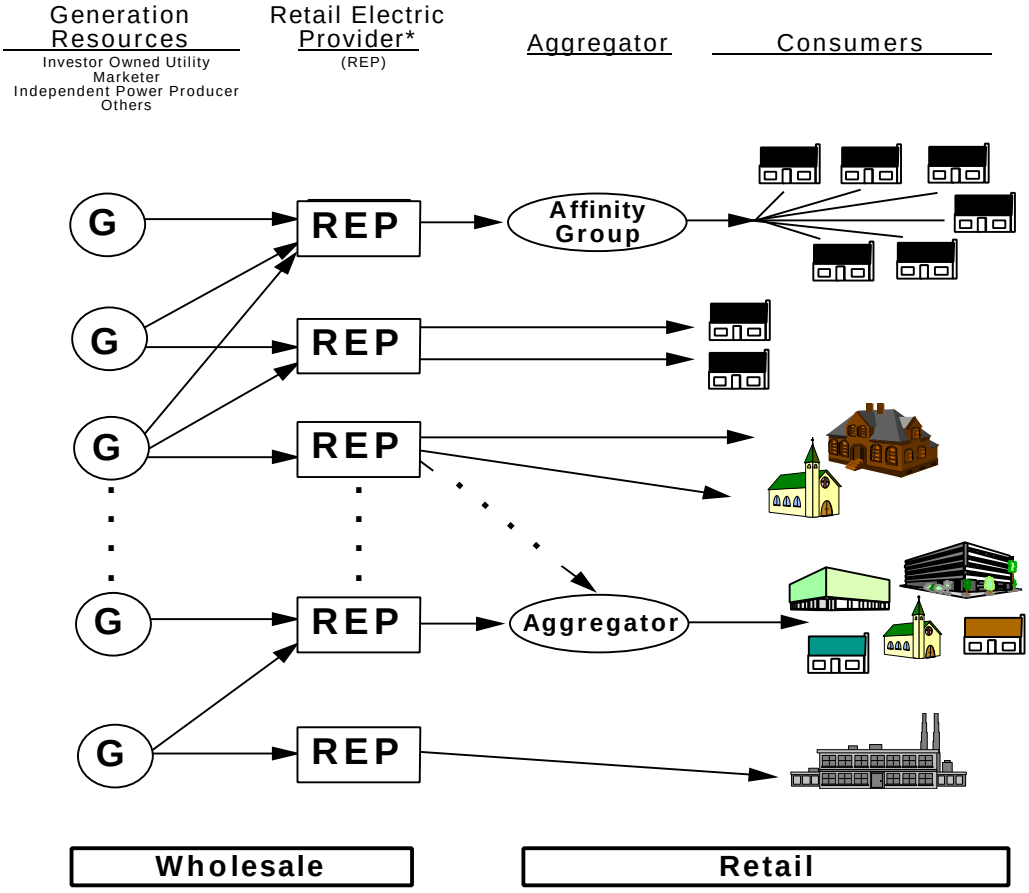
A. INDUSTRY STRUCTURE

This chapter discusses a retail competition structure under which electric consumers would have direct access to REPs. Under this structure, the generation, REP and customer service sectors would be competitive. Transmission and distribution services would continue to be provided under regulated utility tariffs. The diagram at the end of this section shows the key market entities and their relationships in terms of the flows of information, electricity and compensation.

The principal difference between this structure and the others proposed is that this structure would not include any form of institutionalized power exchange or pool. Rather, each consumer and each seller can contract individually for a customized arrangement that meets each party=s needs. In addition, standard offer packages will be available directly or through aggregators for those consumers who do not wish to negotiate an individual arrangement with a REP. The following diagram shows the various entities and possible arrangements that would be made for the delivery of power in a direct access market structure.

[19] Missouri Industrial Energy Consumers, Enron Corp., and QST Enterprises, Inc. provided presentations and the initial drafts for the direct access structure described in this chapter.

DIRECT ACCESS MARKET STRUCTURE



*The REP could generate its own power rather than purchase it in the wholesale electricity market.

While the direct access market structure does not include a formal power exchange or pool, it does require that REPs schedule power to meet their forecasted load. To ensure that REPs maintain hour-to-hour load balancing, penalties would be applied to REPs who fail to deliver power to match their hourly load forecast.

To the extent that REPs cannot perform their own moment-to-moment load balancing (e.g., through dynamic scheduling or other means), this balancing will be provided as an ancillary transmission service using the Federal Energy Regulatory Commission=s (FERC=s) pro forma open access transmission tariffs. In addition, to the extent that REPs do not provide their share of operating reserves, these services would also be provided using the FERC >s pro forma open access transmission tariff.[20]

(1) Generation Business Unit

Under a direct access structure, REPs would acquire supplies through some combination of outright ownership of generation and bilateral contracts for supplies. Bilateral contracts for supplies would be obtained by REPs from the wholesale market. Suppliers in the wholesale market would sell to REPs either on an unregulated basis, under cost-based rates regulated by FERC, or under market-based rate authority granted by FERC. REPs would obtain wholesale price discovery through futures exchanges, such as those currently operated by the New York Mercantile Exchange (NYMEX), surveys such as those prepared by Power Markets Week, and electronic transaction matching exchanges, such as the one operated by the Continental Power Exchange (CPEX). Existing electric utilities would be required, at a minimum, to functionally separate their generation from their other activities, such as transmission, distribution and retail services.

[20] If an Independent System Operator (ISO) is implemented, then the forecasting, scheduling, balancing, voltage support, losses and operation reserves would be arranged by the REPs with the ISO. If an ISO is not implemented, then these arrangements would be made with the functionally separated transmission business unit of the incumbent utility.

(a) Forecasting Load, Planning Capacity and Scheduling Generation

REPs would be responsible for scheduling supplies to meet the hourly forecast of their load responsibility. REPs need to have a reasonable forecast of the characteristics of the loads for which they are responsible. In addition, the sum of the individual REP forecasts must equal the ISO=s forecast for total system load. Utilities today forecast their own load on an aggregate basis, both for the near-term and the long-term . These forecasts are generally developed by combining load research (sample) data for groups of smaller customers with customer-specific information for large loads. To facilitate retail access, the ISO would develop and post aggregate load forecasts for each REP.[21] These forecasts would be posted privately for each REP on a high-performance electronic network. On a rolling basis, these postings would be as follows:

- Peak load, minimum load and load factor seasonally for the next ten years
- Peak load, minimum load and load factor monthly for the next 12 months
- Peak load, minimum load and load factor weekly for the next 12 weeks
- Peak load, minimum load and load factor daily for the next 30 days
- Hourly load for the next 168 hours

These forecasts would be updated hourly by the ISO.

[21] It is anticipated that after the initial startup of retail competition, REPs would be permitted to forecast their own loads. However, it would be necessary for the REP to provide to the ISO a forecast of its load in the same form that the ISO would have provided it to the REP. In addition, penalties would most likely need to be established for those REPs who consistently forecast their load less accurately than the ISO.

REPs would use their hourly load forecasts to dispatch their supplies and enter into spot bilateral wholesale transactions as needed to meet these forecasted loads in future hours. Consistent with the FERC pro-forma, open access transmission tariff, REPs would have until 20 minutes prior to the hour of operation to adjust the delivery schedule of their supplies to match their updated hourly load forecasts. To maximize the likelihood that REPs as a group would maintain hour-to-hour system balance, REPs would be subject to severe penalties for under-delivery or over-delivery versus their forecasted load. To the extent that REPs as a group fail to maintain hour-to-hour system balance, the ISO would correct for this mismatch as part of its provision of moment-to-moment system balancing.[22] REPs would use their daily load forecasts to commit[23] their supplies and enter into daily bilateral wholesale transactions in order to have sufficient dispatchable supplies available to match their forecasted load on future days. REPs would schedule maintenance on their supplies and acquire resources from the wholesale market on an intermediate-term basis to ensure they will have sufficient supplies on hand to meet their forecasted weekly and monthly loads. REPs would construct new generation facilities, install load management systems (to shave the peak of their loads), manage the interruptibility provisions of their retail commitments, and/or contractually acquire resources on a long-term basis from the wholesale market to ensure they have supplies sufficient to meet

[22] The ISO also would have the ability to enter into call options with consumers to interrupt load instantaneously in order to cover severe generation deficiencies. The costs to enter into the call options could be included as part of the rate for Regulation and Frequency Response Service.

[23] A major portion of installed generating capacity in Missouri is powered by steam turbines fed by a boiler fired by coal, oil or natural gas. Generally, steam powered generation must be brought on-line several hours before it can be dispatched to meet hourly loads. In addition, when steam powered generation is taken off-line, several hours must pass before that generation can be brought on-line again. The commitment of generation is the process of placing steam powered generation on-line in anticipation of needing power from that generation in future hours.

their forecasted seasonal loads in future years. The incentive for REPs to perform this generation planning on a day-to-day through year-to-year basis is that if they are caught Ashort@ in the future, they would be subject to penalties for not delivering power to match their hourly forecasted loads. The intent of these incentives is to provide for planned generation reserves without any other requirement beyond the penalties.

(b) Balancing Moment-To-Moment Generation With Load and Other Ancillary Services

For moment-to-moment load balancing, REPs should have the option to install the equipment necessary to dynamically schedule part or all of their generation to their load. To the extent that a REP does not use dynamic scheduling, it would be required to purchase Regulation and Frequency Response Service, as well as Energy Imbalance Service, from the ISO.[24] A REP can satisfy its requirements for these services either completely, or in part, by placing under the control of the ISO the generating capacity with Automatic Generation Control (AGC) capability that it has acquired.

REPs will need to purchase their share of operating reserves from the ISO. However, REPs may satisfy their requirement to purchase these services either completely, or in part, by turning control of generating capacity capable of providing these reserves over to the control of the ISO. REPs will also need to either provide for transmission losses or purchase them from the wholesale market. In addition, to the extent the REP cannot provide its own dynamic voltage support, they will need to purchase Reactive Supply and Voltage Control for Generation Sources Service from the ISO.

[24] One of the responsibilities of the ISO is to maintain system reliability. For convenience, some of these reliability functions are mentioned in this section, rather than in the next section on transmission.

In order to provide the moment-to-moment balancing and other ancillary services, the ISO would only need to acquire a minimal amount of generating resources. The ISO could acquire these generation resources through RFPs issued to the marketplace.[25] For the generation capacity required for moment-to-moment system balancing and other ancillary services, the ISO could contract to reserve capacity in the form of a call option to take electricity only when it is required. Energy would only be taken from this reserve capacity when the ISO needs it to balance the system or provide power for the other ancillary services. The ISO would recover its costs for both capacity and energy through its FERC regulated ancillary service rates.

(c) Settlements on Energy Imbalances

In the direct access model, there is a need for REPs to clear their energy imbalances caused by actual loads being different from forecasted loads. Settlements of energy imbalances could take place on a day-to-day basis (first settlements market) for differences between hourly loads and hourly load forecasts, and will need to take place on a monthly basis (second settlements market) for meter reading delays for end-use consumers not on hourly meter reading.

The first settlements market would be used to clear any energy imbalances related to forecast errors, moment-to-moment load fluctuations and system disturbances as estimated or measured shortly after the hour of actual operation. This settlement market would commence immediately after the ISO publicly posts on an electronic network the hourly energy imbalances

[25] However, if certain generation is uniquely situated to provide dynamic voltage control, the rates under which such reactive power and voltage control is sold to the ISO should be cost-based reflecting the natural monopoly status that generator has in providing the service.

for each REP along with the ISO=s hourly incremental energy cost for imbalances. The REPs then would have a number of days (possibly five) to resolve these imbalances bilaterally among themselves. At the end of the settlement period, any remaining over-deliveries would be paid to REPs at a discount of less than 100% of the ISO=s incremental energy cost for imbalances. The remaining under-delivery would be charged to REPs at a premium of more than 100% of the incremental energy cost.

The second settlements market would be used to resolve the difference between the forecasted versus the actual load for consumers not on hourly meter reading. This market would commence at the end of each month. The ISO would post all energy imbalances due to this metering correction publicly on an electronic information network. Once again, REPs would have a number of days (possibly five) to resolve all imbalances among themselves. Any imbalances not resolved among the REPs themselves will involve discounts on ISO payments to REPs or premiums on REP payments to the ISO.

The purpose of the discounts collected from and premiums paid by the REPs with energy imbalances remaining at the conclusion of each of the two settlement markets is to serve as an incentive for REPs to resolve such imbalance among themselves without the involvement of the ISO.[26] The net revenues collected by the ISO from energy imbalances as well as from the penalties for REPs not scheduling to meet their load forecasts should be applied as revenue credits to the ISO=s FERC transmission tariffs.

[26] These penalties also serve as an incentive for REPs to invest in real-time metering and telemetering of their customers= loads. Through the use of improved metering REPs will be able to reduce the amount of settlement they have to perform after the conclusion of system operation. In addition, it will aid them in developing load forecasts superior to that of the ISO and help open the door toward a greater use of dynamic scheduling.

(2) Transmission Business Unit

The FERC would regulate the transmission and ancillary service rates of the ISO. This structure does not require a power exchange or pool.[27]

Depending on the choice of the consumer, the ISO will either bill the REP or the LDU for transmission service for that consumer. The REP or LDU, in turn, would then bill individual consumers for their use of the transmission system. Regardless of who performs the billing to the consumer, the REP will be responsible for scheduling all transmission service for its customers.

(3) Retail Electric Provider Business Unit

[27] However, the market would be permitted on its own to create trading hubs, on-line transaction matching systems and other forms of voluntary power exchanges to the extent the market found the need and advantage in doing so. Such exchanges would be financially supported by those market participants who saw benefit in using them.

As stated earlier, under direct access, REPs would own or directly contract on a bilateral basis for generation. Consumers (or groups of consumers, at the individual consumer=s option) would have direct access to REPs. This direct access would take the form of individually negotiated contracts and standard offers of service.[28] Those consumers who wish to take advantage of the benefits of individually negotiated contracts, without actually negotiating those contracts themselves, could subscribe to the services of a load aggregator who may or may not be a REP itself.[29] This market structure allows both consumers and sellers to customize transactions for their mutual benefit. Also, as stated earlier, REPs would have the responsibility of maintaining long-term and hour-to-hour system balance for their contracted load. To accomplish these objectives, REPs would perform their own generation planning.

Generators, marketers and utility affiliates could all become REPs. In addition, individual consumers, or groups of electric consumers, could become REPs. All REPs serving residential and small business customers would be certified by the MoPSC in order to protect consumers. However, such certification should not be so burdensome that it creates a barrier to market entry.

Consumers who elect to do so would be allowed to continue to receive service from their local utility, and would pay the applicable standard rate or offer of the LDU=s retail marketing

[28] A standard offer of service can be thought of as an unregulated tariff for service with different pricing for identified levels or types of service that is available to any consumer in a given class. REPs would not be obligated to have standard offers, but it would be to their competitive advantage to do so.

[29] An aggregator that is not a REP must buy power from a certified REP in order to not be subject to REP certification requirements.

affiliate. Consumers who do not make a choice could be allocated among all REPs (including the LDU=s retail market affiliate) based on the level of each REP=s sales to other consumers. Alternatively, the right to serve these consumers could be put out for bid.

(4) Distribution Business Unit

As with transmission service, each consumer could choose to be billed for distribution service by its REP or its LDU.

(5) Customer Service Business Unit

Under direct access, REPs could have an ability to serve as a single point of contact for customer services, such as billing, customer questions, new service requests and customer metering. The customer services offered by REPs will be provided on a competitive basis. However, consumers may also choose to continue to have the LDU serve as the point of contact. Regardless of who provides these services, services such as metering and billing should be subject to strict accuracy standards set by the appropriate state or local authority. To the extent that metering is done on a real-time basis and is used for dynamic scheduling, the ISO would propose the metering standards which would be approved by FERC.

An important consumer service issue is service for high-risk/high-cost consumers and consumers with special needs. Several approaches to this problem might be acceptable. One approach would be allocate them among all REPs based on each REP=s sales to other consumers. To the extent that utilities are currently required to serve these consumers, REPs would be required to serve these consumers under the standard-offer rates provided to other consumers. To help offset the costs of serving these consumers, REPs would receive an allocation of the amounts currently included in the rates of the utilities for bad debts and

collection costs. These would continue to be collected by means of a non-bypassable distribution Awires@ charge paid by all consumers in the same class. Any public funds would similarly be made available to all REPs on a non-discriminatory basis. Another approach would be to compensate the LDU to take on this requirement.

B. POTENTIAL ISSUES

1. Infrastructure Needs.

a) Load Forecasts and Scheduling Generation: In each LDU service territory, the ISO will provide an aggregate load forecast for each REP. At the REP=s option, it may forecast its own load. However, REPs who choose to forecast their own load will be responsible for revising and providing their load forecast for each LDU service territory to the ISO. Also, REPs who choose this option will need access to information on consumer usage that will allow them to make these load forecasts. Such information must initially be made available from the LDUs having this information. The ISO or individual transmission control areas may need to revise submitted forecasts in such a way that the sum of all REP load forecasts equals the ISO=s or individual control area=s forecast of coincident system load.[30] Also, penalties may need to be established to penalize those REPs who forecast their own load less accurately on average than the ISO or individual transmission control areas. Rules regarding load forecasting and penalties should be addressed either by

[30]Whether or not there are ISOs, the individual transmission control area will need to make and revise hourly load forecasts for the load located at the points of delivery within its control area. If there are ISOs, the individual transmission control areas would supply their forecasts to the ISO. In addition, the ISO will likely make adjustments to

the ISO or the individual transmission control areas, and in either case will be subject to approval by the appropriate state or local regulatory authority and the FERC.

b) Scheduling: The REPs will schedule with the ISO or individual transmission control areas the generation needed to meet their load forecasts for each LDU service territory. Rules regarding scheduling will be addressed by the ISO or individual transmission control areas, and, in either case, will be subject to approval by the FERC.

c) Ancillary Services: Arrangements will need to be made between the REPs and the various ISOs or individual transmission control areas for the provision of ancillary services. This should be addressed by either the ISO or the individual transmission control areas, and, in either case, will be subject to approval by the FERC.

d) Balancing: Arrangements for generation needed to meet the difference between forecasted hourly loads and actual hourly loads will need to be coordinated between the REPs and the various affected ISOs or individual transmission control areas. Once REPs have prescheduled their deliveries to meet their forecasted loads, the ISO will arrange for the generation needed to meet the difference between forecasted hourly loads and scheduled deliveries. As the hour of operation approaches, the ISO will update REP load forecasts and REPs will modify their preschedules to match their revised forecasted loads. Once the REPs have revised

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these individual load forecasts in determining its aggregate load forecast.

their schedules, the ISO will revise its generation arrangements to meet the difference between the revised load forecasts and revised delivery schedules. Prior to the hour of actual operation, the ISO will also arrange for any generation necessary to perform its moment-to-moment system balancing function. This should be addressed either by the ISO or the individual transmission control areas, and, in either case, will be subject to approval by the FERC.

e) Settlements: A process will need to be set in place for settlements between the REPs and the ISOs or individual transmission control areas for differences between forecasted and actual hourly usage of electricity. In the direct access structure, settlements are resolved between the REPs themselves with any remaining imbalances being resolved with the ISO.

f) Hourly Metering: The size of customer requiring hourly metering needs to be established. Since this is related to the settlements process, it should be addressed by the ISO or the individual transmission control areas, and, in either case, will be subject to approval by the FERC.

g) Data Access for Billing: Many entities will need access to customer data for purposes of forecasting and billing. This issue should be addressed by the relevant state or local regulatory authority, and will likely be subject to approval by the FERC.

2. Certification of Retail Electric Providers. For purposes of assuring adequacy of electricity supply, certification of REPs will need to be addressed. Requirements to be certified as a REP in the state of Missouri should be addressed by the state legislature.

3. Setting Generation Supply Reliability Requirements. The ISO or individual transmission control areas will need to establish generation supply reliability requirements for the scheduling of generation by the REPs.[31] REPs who fail to deliver supplies to match their forecasted load would be subject to severe penalties. To manage their risk of potential exposure to penalties, REPs will need to manage the reliability of their power supplies. REPs can manage the reliability of their power supplies by performing appropriate maintenance on the generation facilities they own and by specifying reliability requirements in their bilateral contracts with other suppliers. In addition, REPs can either construct or contract in advance for backup supplies. These requirements will be approved by the FERC.

4. Standard Offers. REPs may be required to post standard prices that may differ by customer class/load shape type. These standard offers of service would be available to all individual consumers whose load requirements fit the specific offers of service and who do not want to individually negotiate the prices and terms of service. The Aall takers@ provision could either be applied to REPs statewide or by distribution service territory. The necessity of the standard offer requirement should be determined by the state legislature.

5. Customer Service Unbundling. A significant issue to address is the level to which the customer service functions will be unbundled. Some states are requiring that metering, meter reading and billing be open to retail competition. If metering is open to competition, some of the issues to be addressed include meter testing, installation procedures, quality and the assignment of responsibility. Competitive billing will require new dispute resolution procedures and disclosure requirements. Other service-related issues include connect, disconnect and storm

[31]Generation supply reliability requirements refers to the availability of generators to provide electricity when

restoration rules. The decision to unbundle the customer service functions should be left up to the state legislature, while many of the issues related to implementing unbundling are best left up to the LDU=s state or local regulatory authority.

6. Municipals and Cooperatives: Opt In/Opt Out. The state legislature will need to determine whether municipal and/or cooperative electric systems should be allowed the option not to participate in giving their customers direct access to alternative REPs.

7. Affiliate Transaction Rules and Standards of Conduct. Affiliate transaction rules and standards of conduct for transactions between any Generation/REP function of an existing utility and their regulated operation will be needed. The MoPSC and/or state legislature should address this issue.

C. POTENTIAL STRUCTURAL IMPACTS ON UTILITIES

1. Obligation to Serve. With generation open to competition, the existing utilities will no longer have the obligation to plan for and build new generation. Their existing obligation to serve will be redefined as an obligation to connect consumers to the grid and deliver energy at the market price.

2. Company Structure. Generation will be functionally separated from transmission, distribution and customer services. The separate generation business units will need to decide whether they will compete in the market for generation, or sell off their generation assets. Competition in the market for generation could be either at the wholesale or at the retail level.

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needed.

With transmission separate from generation, the ISO or the individual transmission control areas will need to acquire generation for ancillary services on a competitive basis to meet the requirements of FERC Orders 888 and 888A. With direct access, the transmission customer should also have the option to acquire ancillary services directly from generators or power marketers.

If customer services such as metering, meter reading and billing are offered on a competitive basis, then this part of the traditional utility business will also need to be functionally separated from the distribution wires service of the LDU.

3. Standards of Conduct. Functional separation by way of a code of conduct will, at a minimum, need to be in place between the competitive and non-competitive functions of the utilities. This code of conduct will most likely be set by the MoPSC for the investor-owned utilities. The state legislature will need to decide how the code will be set for Municipal and Cooperative utilities.

4. Rate and Bill Unbundling.

a) Distribution Rates: Separate rates for distribution service from the LDU will be required. These rates will be set by the relevant state or local regulatory authorities.

b) Transmission Rates: If there is an ISO, charges for transmission will be at the ISO rate, rather than at a separate LDU transmission rate. If the LDU is not a member of an ISO, then that LDU=s individual control area transmission rate will be applied. Both the ISO rate and the individual transmission control area rate will be set by the FERC.

c) Regulated Generation Rates: If the LDU would continue to provide generation on a regulated basis, then this service would need to be set out as a separate rate. Rates for regulated generation will be set by the relevant state or local regulatory authorities.

d) Regulated Customer Service Rates: If customer services such as metering, meter reading and billing are offered on a competitive basis and the LDU continues to provide these services on a regulated basis, then the LDU=s regulated charges for these services will also need to be separate. Rates for regulated customer services will be set by the relevant state or local regulatory authorities.

e) Separate Charges on Customer=s Bill: While customers will have the option of paying a single bill, that bill will need to show the separate charges for each component of service.

5. Upgrades to Customer Information Systems. Utility customer information systems (CIS) will most likely require extensive upgrades to track:

- **$** Who the REP is for each customer;
- **$** Who bills for each service;
- **$** Who owns the metering equipment (if metering is competitively provided);
- **$** Who reads the meter (if meter reading is competitively provided);
- **$** What data must be transferred to the ISO, REPs, etc.;
- **$** Rates for alternative REPs (if billing is contracted to the LDU);
- **$** Hourly usage data for larger customers; and
- **$** Hourly profile data for smaller customers.

6. Anti Flip-Flop Laws. The current state law does not allow utilities to compete for existing customers of another utility based on price. In order to implement direct access, this law would need to be rescinded.

D. POTENTIAL IMPACTS ON CONSUMERS

1. Generation Service Options. Consumers will be given the opportunity to choose their electricity provider. Consumer alternatives may include

- **$** Aggregators
- **$** LDU
- **$** Other Alternative REPs

2. Metering and Billing Options. Consumers may have a choice of alternative providers for metering and/or billing services. With these choices, consumers could receive a single bill from either the REP or LDU, or could elect to receive separate bills, one for electricity from the REP and one for delivery services from the LDU.

3. Consumer Education. With new choices for generation, and possibly metering and billing, consumer education will be necessary. Possible sources of consumer education would include the MoPSC, the Office of the Public Counsel (OPC), the LDUs and the REPs. Consumer education should focus on the ways that consumers can elect to obtain electricity and the procedures that consumers need to follow to implement their choices.

4. Sales Practices. Any REP licensed by the state to offer electricity for sale at retail could be required to include with every sales offer a MoPSC-approved Standard Cost Comparison Disclosure form. The Standard Cost Comparison Disclosure would require that REPs uniformly and accurately disclose the true cost, term, conditions, disclaimers and reliability of the service they are offering. The state may also want to assert MoPSC oversight of REP advertisements and sales promotion material to minimize misleading or false claims of price and/or expected savings to the consumer.

5. Generation Reliability. With the use of penalties to REPs for shortages of generation to meet their hourly load forecasts, end-use consumers may see a different level of generation reliability than exists under the current system.[32]. In addition, a variety of interruptible service options for accepting different levels of generation reliability may be made available to end-use consumers by the REPs.

6. Provider of Last Resort. How well the direct access proposal for REPs provide generation services to high-risk/high-cost consumers will need to be evaluated.

a) Bad debt expense may be included as a non-bypassable, distribution wires charge of the LDUs. How information on unpaid bills from REP customers will be provided and audited for purposes of determining the level of the non-bypassable, distribution wires charge as well as the payments to REPs will need to be determined.

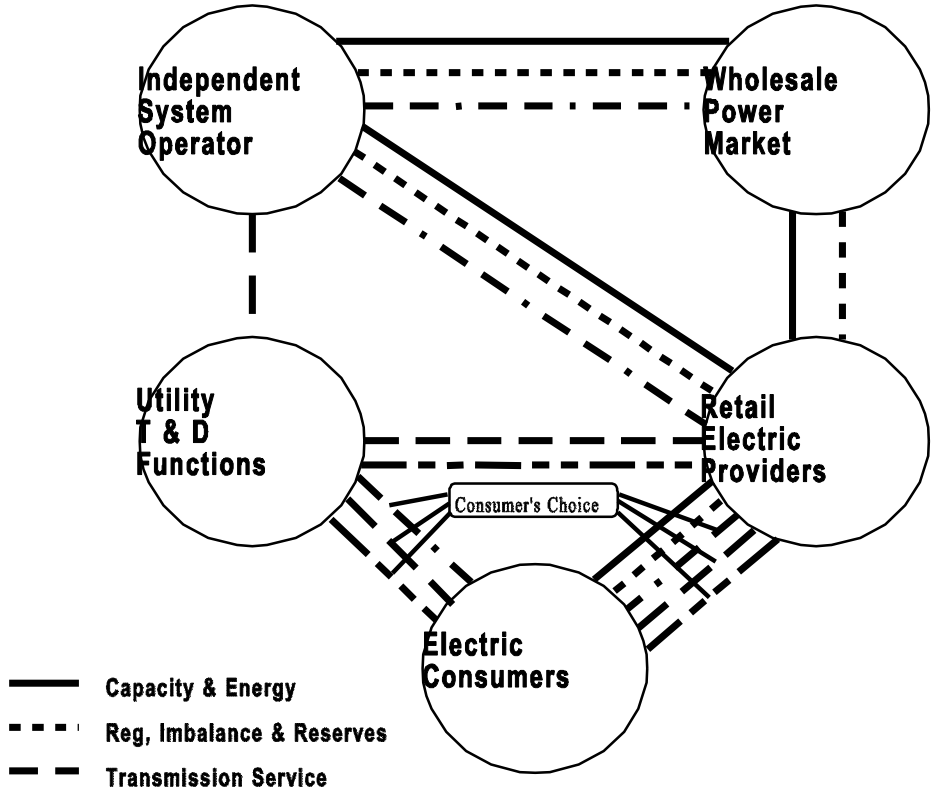
b) The alternative of incorporating bad debt into the REPs: own pricing will need to be considered as an alternative to a non-bypassable, distribution wires charge

7. Assignment of Default Customers. Default customers are those consumers that choose not to choose any particular REP as their service provider. These customers could be assigned to REPs by the appropriate state or local regulatory authority either in proportion to their sales or by a lottery system. Alternatively, the loads of the default customers could be competitively bid by the REPs.

8. Privacy of Consumer Information. There will be a need for REPs to have historical usage information on the specific consumers to whom they will provide electricity. This information will be provided by the LDU serving the consumer only upon first receiving the permission of the consumer.

[32]The current system relies on designed levels of planning reserves for generation to ensure reliability.

Direct Access Market Structure



Note: Individual consumers or groups of consumers may also request to be certified as REPs

Missouri Industrial Energy Consumers

CHAPTER 3
A POOLCO MARKET STRUCTURE [33]

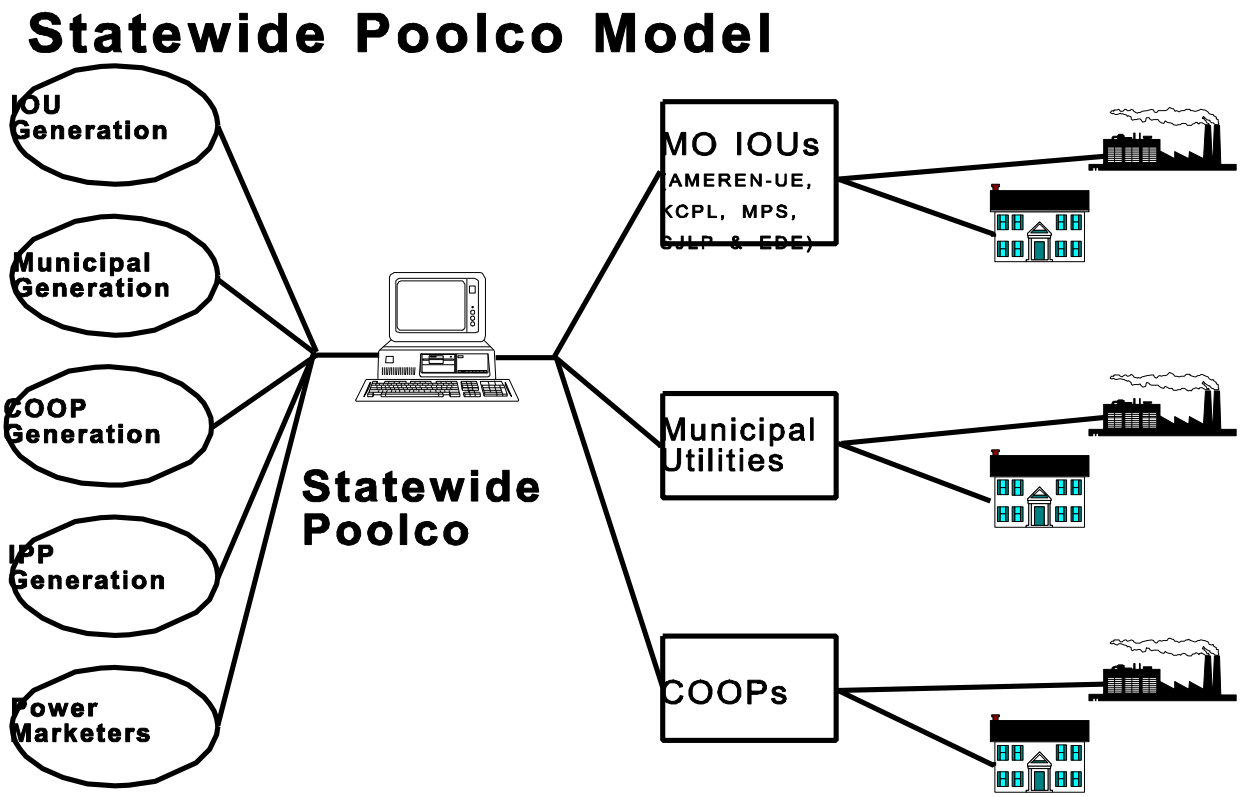
A. INDUSTRY STRUCTURE

The poolco would be set up as an independent entity, acting as a clearinghouse for power transactions. The poolco structure described in this chapter consists of two major components:

1. On the Asupply@ side, the proposal assumes that a single poolco serves the entire state, and that the poolco would take bids to supply the projected power needs of the state from any entity that owns or controls generation. The low bidders would win and would supply the power to the poolco over existing transmission lines.
2. On the Ademand@ side of the poolco, LDU distribution systems would buy all of their power from the poolco at the competitive market clearing price established by the bidding system and would distribute that power to all of the customers within their respective service areas. Alternatively, the power could be purchased at the bid price rather than the market clearing price (or at some price between the two). This option would need to be reviewed relative to its potential impact on customers, and on generation market participation and liquidity.

This poolco structure is depicted in the following diagram.

[33] Union Electric Company provided a presentation and the initial drafts of the poolco market structure described in this chapter.



(1) Generation Business Unit

The price of generation would be Aunbundled@ (or separated) from the rates presently charged and would be determined by the competitive market price as established through the poolco bidding process. Generating plants would no longer have a Acaptive@ customer base, and could sell their output only to the extent that their power was competitively priced.

For sales of electricity to Missouri end-use consumers, all generation would be required to be sold to the poolco except that municipals and cooperatives could be excluded. Any qualified supplier could bid into the poolco, while Missouri utility generators could bid their generation into a qualifying supplier=s system outside the state. Independent generators, in-state or out-of-state, would also be eligible to bid into the poolco.

While the poolco proposal would allow Missouri-based generators to bid their generation into any other state=s system, some established phase-in period may be desirable from the consumers= perspective before this aspect of the plan is implemented. It would also be each Missouri-based generator=s choice whether to bid all of their generation into the poolco as a single package or as individual power plants.

LDUs would provide projected demands to the poolco on an annual, monthly, and weekly basis. For each period, the poolco would aggregate the projected demands of the LDUs, repackage the aggregated demands as blocks of power with different sizes and shapes and put out the blocks for bid to all qualified suppliers, as illustrated below. Another approach would be to allow the LDUs to solicit and select bidders directly. The spot, or day-ahead, market would be handled by the poolco and used to meet daily demands or to beat the incremental price of any of the poolco bid packages that allow flexible scheduling.

Planning for future demand would also be handled through the poolco. Demand forecasts through the next calendar year provided by the LDUs would be bid with an additional component for reserve margin to secure reliable resources. Longer term load forecasts (e.g., up to five years) would be provided by the LDUs to the poolco, and would be used as the basis for signaling the competitive generation market as to the need for future capacity additions.

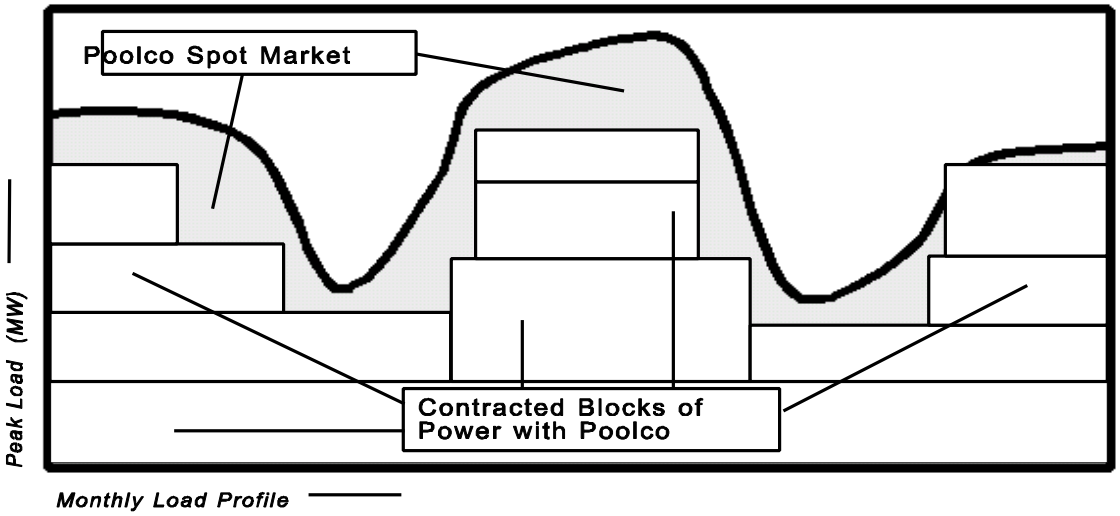
(2) Poolco=s Hourly Pricing Mechanism

The following discussion illustrates how multiple market clearing prices for a given hour are condensed down into a single hourly market clearing price.

Assume that on a typical on-peak hour, the poolco has an aggregated load requirement of its members of 11,000 MW, and that the poolco has solicited bids from multiple generation suppliers for various block types and sizes at prevailing market prices.

The following are the blocks of power the poolco has contracted for with its generation suppliers to meet its aggregated load, along with the corresponding average price the poolco paid its suppliers for each block.

Major Components of the Poolco Model



Block Type	Average Block Size	Total Block Price	Block Price
Base (monthly)	5,000 MW	$20/MWh	$100,000
Intermediate (monthly)	2,500 MW	$24/MWh	$60,000
Intermediate (weekly)	1,500 MW	$28/MWh	$42,000
Intermediate (weekly)	1,000 MW	$30/MWh	$30,000
Peaking (weekly)	500 MW	$50/MWh	$25,000
Spot Market (daily)	500 MW	$45/MWh	$22,500
Total On-Peak	11,000 MW	$25.40/MWh	$279,500

Under this example, the poolco paid an average of $25.40/MWh for the power it contracted to meets its aggregated load requirements. The price that the poolco would charge to its member utilities would be the $25.40/MWh plus an amount to cover the administrative and operating expenses of the poolco. If the poolco=s overhead expenses amounted to an average of $0.10/MWh, the price the poolco would charge to each member LDU for this typical on-peak hour would be $25.40 + $0.10 = $25.50/MWh.

For this example, suppose that Member LDU A had an on-peak load for this hour of 6,000 MW. LDU A=s bill for this on-peak hour would be:

6,000 MW x $25.50/MWh x 1 hour = $153,000.

This price could also be adjusted for varying load factors by calculating a LDU=s proportionate use of each block and summing these blocks.

The above describes the pricing of energy. However, for the contract blocks of power, it is possible that capacity reservation charges would be included as a part of the bids of the generators. If so, these capacity reservation charges must be recovered from the LDUs. Since each LDU has provided the poolco with projected demands which have been repackaged as aggregated blocks of power with different sizes and shapes, the poolco will need to determine how much each LDU has contributed to each of the various blocks of power. Based on this determination, the capacity reservation charges would be allocated to each LDU. In addition,

there may be a spot market for capacity[34] whose cost would also need to be allocated to each of the LDUs.

(3) Setting End-Use Consumer Prices

The ultimate price to the consumer would be set for investor-owned utilities by the appropriate state, or local regulatory authority. The authority to review the prudence of power purchases by the poolco will likely rest with the FERC. State or local regulatory authorities may not be able to deny recovery of any portion of an investor-owned LDU=s mandated power purchases from the poolco. The prices for the distribution and transmission businesses could be set much as they are today. For generation, however, the utilities= traditional costs of owning, operating and maintaining their power plants would be replaced entirely by the market cost of the power purchased from the poolco, plus an adder for poolco operating expenses.

Cooperatives and municipals could continue to set rates as they do today, without any regulatory oversight. However, if they were required to purchase power from the poolco, then their rates presumably would reflect the cost of this power, as opposed to the cost of their existing generation or contracts.

(4) Alternative Pricing Through Contracts for Differences

[34] Spot-market capacity is the capacity required to provide firm energy, and shouldn=t be confused with the capacity required to provide operating reserves. The allocation method for the spot-market capacity charges would then be based on each LDU=s use of spot-market, firm energy.

Financial contracts for electricity can be available through what are called contracts for differences (CFDs). While these financial contracts can become very complex to meet the needs of sophisticated end-use customers, CFDs are simple in concept. The supplier and the end-use consumer agree to a price for electricity. If the price the end-use consumer is charged by the pool[35] is greater than the agreed to price, the supplier pays the end-use consumer the difference. If the price the end-use consumer is charged by the pool is less than the agreed to price, the end-use consumer pays the supplier the difference.

One purpose of the CFDs is to mitigate the risk of price uncertainty in the pool. Both suppliers and end-use consumers may desire price surety, and if they negotiate an agreed to price, then both parties are better off. In addition, certain end-use consumers that have special risk or load needs, may be able to arrange CFD specialty products that are not otherwise available through the pool. In this case, CFDs would play the role of providing specialty services to various niche markets for electricity.

It may be important to the development of the CFD market that the pool pricing not result in shifting the risk of price uncertainty onto the suppliers offering CFDs to end-use consumers. This shifting of risk occurs when there is an opportunity for the price paid to the supplier by the pool to be different from the price charged to the end-use consumer by the pool.

[35] In order for CFD markets to develop, end-use consumers need to be given transparent pricing to the products which the pool is purchasing. If the pool only makes hourly purchases, then end-use consumers would be given the option by their LDUs for real-time (hourly) pricing in which they are charged the same hourly price that the pool is paying to suppliers. If the pool is purchasing multiple products, then end-use consumers will need to be given the option to nominate the amounts of each product that they wish to take to meet their loads.

Consider the following example. Suppose all suppliers are paid their bid prices rather than the same Amarket clearing price.@ Suppose all consumers are then charged the average of the prices paid to all suppliers - the average pool price. In this case, those suppliers with CFDs that have bid at prices below what turns out to be the average pool price, will lose the difference between their bid prices and the average pool price from what they intended to be the fixed price payment in the CFD.[36] This problem can be addressed through either some form of market clearing pricing, where all suppliers of the same kinds of products are paid the same price, or through the pool allowing suppliers with CFDs to nominate supplies to meet the loads of end-use customers with whom they have CFDs and are then paid the average pool price for these supplies.[37]

(5) Transmission Business Unit

LDUs would continue to own their transmission lines, but jurisdictional control of transmission could be turned over to an ISO. The poolco would provide market-related functions only, and would not be set up to govern reliability-related issues. Instead, these issues would be left to the LDU control areas or the utilities= respective ISO, if applicable. The potential role of the ISO is described in the first chapter of this report.

(6) Distribution Business Unit

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[36]For example, suppose the consumer pays the average pool price of 3¢/kWh, but the supplier is only paid its bid of 2.5¢/kWh. Assume that the CFD is also for 2.5¢/kWh, so that the supplier must make up the difference between what the consumer pays and the CFD. This amount is 0.5¢/kWh = 3¢/kWh - 2.5¢/kWh. Since the supplier is only receiving 2.5¢/kWh rather than the 3¢/kWh paid by the consumer, this 0.5¢/kWh difference will come out of the supplier=s pocket rather than from what the supplier would have received from the pool had it been paid the same price as the end-use consumer. If suppliers are faced with this risk, the CFD market will likely be less robust.

[37]This is similar to noncompetitive bids that are accepted in the Treasury bill auction. Noncompetitive bids are those bids for a given quantity of Treasury bills to those willing to pay the average price of the accepted bids that included prices. While noncompetitive bids can be offered by anyone, government agencies wanting to buy Treasury bills must purchase them on a noncompetitive basis.

The LDU would be responsible for submitting its load projections to the poolco to acquire generation from the poolco, allowing for a portfolio of resources to serve its load. The market clearing price charged to all LDUs would be based on the average hourly cost of power acquired by the poolco in order to satisfy the poolco=s aggregated load requirements. Prices paid could include both demand and energy cost components.

The LDU would continue to be solely responsible for the tasks of the REP and for Customer Services (metering, meter reading, billing, etc.). In the future, however, some or all of these services could also be opened to full competition.

B. POTENTIAL ISSUES

1. Infrastructure Needs.

a) Load Forecasts and Scheduling Generation: The LDUs will be responsible for providing and revising their load forecasts to the poolco. Rules about load forecasting should be addressed in the poolco=s rules, and will be subject to approval by the FERC.

b) Scheduling: The poolco will schedule the generation to meet the aggregated forecasts from all the LDUs. Rules about scheduling should be addressed in the poolco=s rules, and will be subject to approval by the FERC.

b) Ancillary Services: Arrangements will need to be made between the poolco and the various ISOs or individual transmission control areas for the provision of ancillary services. This should be addressed in the poolco=s rules, and will be subject to approval by the FERC.

c) Balancing: Arrangements for generation needed to meet the difference between forecasted hourly loads and actual hourly loads will need to be coordinated between the poolco and the various affected ISOs or individual transmission control areas. This should be addressed in the poolco=s rules, and will be subject to approval by the FERC.

d) Settlements: A process will need to be set in place by the poolco for settlements between the poolco and the LDUs for differences between forecasted and actual hourly usage of electricity. This should be addressed in the poolco=s rules, and will be subject to approval by the FERC.

e) Hourly Metering: Consumers wanting to enter into CFDs will require either hourly metering of their usage or utilization of an hourly load profile in order to be priced by the poolco at its hourly price for electricity.

2. Certification of Contracts for Differences Dealers. For purposes of assuring financial protection, certification of CFD dealers may need to be addressed. Requirements to be certified as a CFD dealer in the state of Missouri should be addressed by the state legislature.

3. Setting Generation Supply Reliability Requirements. The poolco will need to establish the generation supply reliability requirements of the power supply packages in its bid requests.[38] These requirements will be approved by the FERC.

4. Purchased Power Cost Recovery for LDUs. With the cost of generation being established by competition - as opposed to the utilities' own costs - prices are likely to be more volatile. Therefore, it may be desirable to develop new methods to reflect the changing market price - such as a system comparable to the Purchased Gas Adjustment (PGA) clause used in the natural gas business. Like the PGA clause, this system would allow prices paid by consumers to better track the changes in market prices, and ensure that the LDU recovers the cost of the power it buys from the poolco. This PGA type of mechanism would need to be approved by the state legislature.

5. Rate Design Flexibility. Another issue related to the price volatility of generation is the level of flexibility that should be given to LDUs in designing rates. For example, the LDU may be required to pay the poolco based on hourly prices, but can it average those prices for some

[38]Generation supply reliability requirements refers to the availability of generators to provide the electricity when needed.

customers, while offering real-time pricing for others? Allowing LDUs to offer flexible pricing mechanisms to customers would provide customers with options not now available. Any flexibility in designing rates would require appropriate state or local regulatory oversight and approval.

6. Competitive Provision of Customer Metering. Under the poolco structure customer metering could be provided on a competitive basis. If metering is open to competition, some of the issues to be addressed include meter testing, installation procedures, quality and the assignment of responsibility. The decision to competitively provide customer metering should be left up to the state legislature, while many of the issues related to implementing competitively provided metering are best left up to the LDU=s state or local regulatory authority.

7. Municipals / Cooperatives: Opt In / Opt Out. The state legislature will need to determine whether municipal and/or cooperative electric systems should be allowed the option not to participate in the power pool either as a seller or as a buyer. Under federal law, cooperative and municipal systems are allowed to purchase wholesale power in the competitive market. Thus, the State of Missouri may not legally be able to require those entities to purchase any or all of their power from a poolco.

8. Rules for the Bidding of Generation. In order to provide a level playing field for all generators and power marketers, rules for the bidding of generation will need to be established by the poolco. These rules will need to be approved by the FERC.

9. Poolco Approval and Oversight. Establishment of the poolco and its management structure would likely require legislative approval, while governance and operating issues would require regulatory oversight and approval by the FERC.

C. Potential Structural Impacts on Utilities

1. Obligation to Serve. With generation open to competition, the LDUs will no longer have the obligation to plan for and build new generation. Their existing obligation to serve will be redefined as an obligation to connect consumers to the grid, submit their load forecasts to the poolco and deliver energy at the market price. It will become the poolco=s obligation to acquire the generation supplies needed to meet the aggregate load forecasts of the LDUs.

2. Company Structure. Generation will be functionally separated from transmission and distribution. The separate generation business unit would compete in the wholesale market for electricity by submitting offers to either the poolco for supply of direct power requirements or to the ISO or individual transmission control areas for ancillary services. With transmission separate from generation, either the ISO or the individual transmission control areas will need to acquire generation for ancillary services on a competitive bid basis.

3. Standards of Conduct. Functional separation by way of a code of conduct will, at a minimum, need to be in place between the competitive and non-competitive functions of the utilities. This code of conduct will most likely be set by the MoPSC for the investor-owned utilities. The state legislature will need to decide how the code will be set for municipal and cooperative utilities.

4. Rate and Bill Unbundling.

a) Distribution Rates: Separate rates for distribution service from the LDU will be required. These rates will be set by the relevant state or local regulatory authority.

b) Transmission Rates: If there is an ISO, charges for transmission will be at the ISO rate, rather than at a separate LDU transmission rate. If a particular LDU is not a

member of an ISO, that LDU=s individual control area transmission rate will be applied. Both the ISO rate and the individual transmission control area rate will be set by the FERC.

c) Regulated Generation Rates: The LDU will continue to provide generation on a regulated basis, but since this service will likely be subject to adjustment as costs change at the poolco, the costs paid for generation from the poolco should be set out as a separate rate. The wholesale generation prices will be determined in the competitive market.

d) Regulated Customer Service Rates: If customer services such as metering, meter reading and billing are offered on a competitive basis and the LDU continues to provide these services on a regulated basis, then the LDU=s regulated charges for these services will also need to be separate. Rates for regulated customer services will be set by the relevant state or local regulatory authority.

e) Separate Charges on Customer=s Bill: While customers will have the option of paying a single bill, that bill will need to show the separate charges for each component of service.

D. POTENTIAL IMPACTS ON CONSUMERS

1. Consumer Choice. With the poolco proposal, consumers do not choose the supplier of their electricity. Suppliers are determined on the basis of their bids to the poolco, and the utility serves the function of local REP. However, consumers who believe they could do better than the poolco price would be allowed to enter into financial Acontracts for differences@ with any

other supplier.[39] **2. Marketing Costs.** Marketing costs and efforts will likely be limited to attracting those consumers wanting contracts for differences.

3. Supplier of Last Resort. In the poolco model the LDU is the local REP for all consumers, including high-risk/high-cost consumers.

4. Single Customer Bill. Under the poolco model, consumers would initially receive a single bill for generation, transmission, distribution and customer services from their local utility. The competitive provision of metering and billing would be evaluated as a future option for customer choice.

5. Consumer Education. Under the poolco model, consumers would still be purchasing from the local utility at a tariffed price, but with the possible addition of a purchased power adjustment. Thus, consumer education would focus on changes in rates associated with the changing prices that are occurring in the wholesale market and not on how to choose among competing REPs.

6. Generation Reliability. Because the LDU will no longer build and operate generation, end-use consumers may see a different level of generation reliability than exists under the current system which uses designed levels of planning reserves for generation. In addition, a

[39] Contracts for differences involve a supplier and customer agreeing on a price for electricity. If the poolco price is different from the contract price, then that difference is made up as a payment from the supplier to the customer when the poolco price is higher than the contract price or as a payment from the customer to the supplier when the poolco price is lower than the contract price. This allows a customer to secure a fixed or indexed price with the supplier managing the risk of uncertainty in the poolco price.

variety of interruptible service options for accepting different levels of generation reliability may be made available to end-use customers.

7. Privacy of Consumer Information. There will be a need for those wanting to offer CFDs to have historical usage information on the specific consumers to whom they are providing CFDs. This information will be provided by the LDU serving the consumer only upon first receiving the permission of the consumer.

CHAPTER 4
A HYBRID MARKET STRUCTURE [40]

A. DESCRIPTION OF THE STRUCTURE

The hybrid structure combines aspects of both the direct access (bilateral contracts) market structure and the poolco (regional power exchange) structure. Under this hybrid structure, an Independent System Operator (ISO) facilitates the dispatch of generation and operation of the transmission system to meet the load requirements of bilateral contracts and spot market purchases through a regional Power Exchange (PX). The distribution of electricity will remain as it is under the current regulated structure. Unbundling of the customer service function (opening metering, meter reading and billing to competition) is optional.

(1) Generation Business Unit

Generation is open to full competition. The market will decide what, where and when to build new generation and will set the prices received for electricity by owners of generation assets. New generation will be built when the market price of energy and/or capacity make it economic to do so. Rates for generating electricity will no longer be established by the regulatory authorities. Prices will be established through either contract negotiations (bilateral market) or through the competitively bid PX.

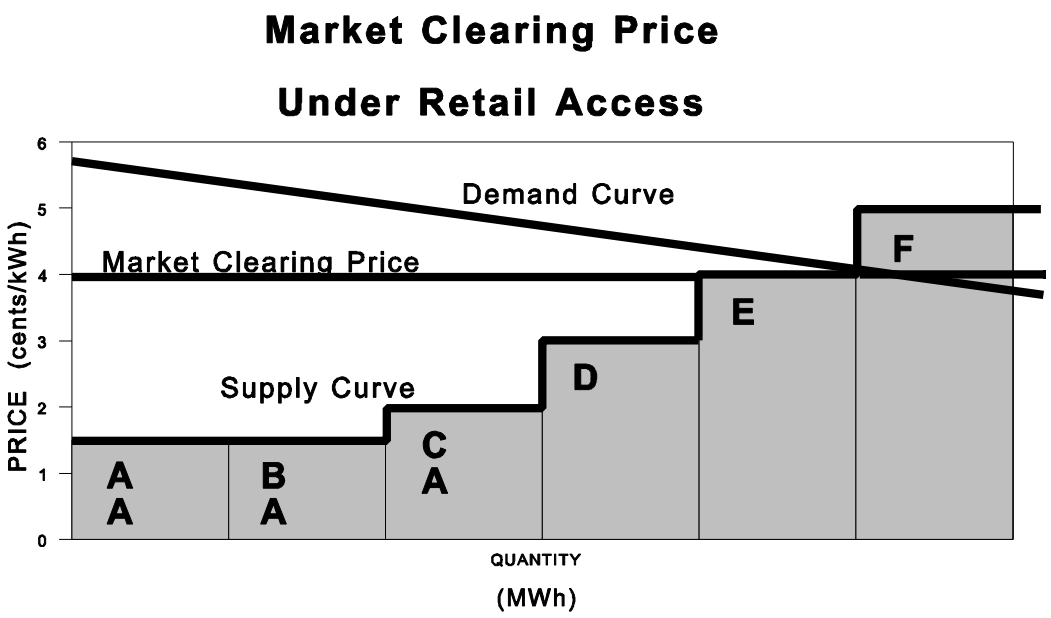
[40] Kansas City Power and Light Company provided a presentation and the initial drafts of the hybrid market structure that is presented in this chapter.

For those buying power from the PX, prices will be established by the PX taking bids from sellers and matching this with the demand from buyers. While price could be set as the average prices paid by the PX for bilateral contracts as described in the poolco structure chapter, in this chapter, the concept of having a market clearing price (MCP)[41] paid to all generators supplying power to the PX is explained.

In the case where a MCP is determined for suppliers, the ISO will then order the dispatch of generation based on the lowest to highest bids that meet the demand from those buyers using the PX. The MCP for power will be set based on the bid from the last unit actually dispatched to meet the load requirement. All bidders who are dispatched receive this price for their generation. If a generator bids too high, it will not be dispatched and therefore receive no revenue. Bids and offers to buy will be taken on a day-ahead basis for each hour or half hour. This is, in effect, pricing for what is called the spot market for electricity.

The following chart illustrates how the MCP is established by the PX. Each bar (A through F) represents a generator=s bid to supply power to the PX. In this example, generators A through E are required to meet demand. The MCP would then be set at 4**4**/kWh for all purchases and sales through the PX.

[41]In the subsequent discussion on market clearing price, the spot-market for electricity is seen primarily as the hourly market required for pricing differences between what REPs have scheduled as supplies and what their customers have actually taken from the grid. To the extent that the PX is involved in acquiring generation on a longer-term basis (such as providing electricity to LDUs for customers that opt not to choose an alternative REP), the PX may want to have the option of being able to purchase this power on either a competitive bid or negotiated contract basis where the supplier is paid a bid or negotiated price rather than an hourly, market clearing price. This option should be given



While most of the generation will be dispatched based on economics (lowest cost first), the ISO may dispatch higher priced renewable generation, also known as Agreen power,@ to meet the requirements of bilateral contracts for such power.

careful consideration when developing the detailed functions for the PX.

A pricing rule that pays every supplier the MCP will relieve bidders of the burden of trying to guess the market price. Suppliers knowledge that they will receive the MCP in every case that their generation is dispatched, should provide an incentive to be dispatched in all cases where the MCP at least covers their variable operating costs. Hence, the MCP approach should encourage bidders to bid their true operating costs, which results in the least-cost dispatch possible.[42] Any difference between the MCP and the suppliers= bids (at variable cost) will go towards covering their fixed generation costs.

MCPs will be location specific. If there are no transmission constraints within a region, the MCP from the PX will be the same for all purchases in the region. It is the inability to move power from one location to another that will create these locational differences in price. Prices will be higher in constrained areas as higher priced generation will be dispatched to meet load requirements that cannot be met with lower priced generation from outside the constrained areas.

Generators will have the choice of selling to the wholesale markets, selling to REPs, selling to the PX, becoming a REP and selling to individual customers, or all of the above.

(2) Retail Electric Provider Business Unit

REPs may consist of marketers, generators or aggregators. There is no requirement that a REP own any generation, transmission or distribution assets. REPs that purchase power for resale may buy it through bilateral contracts or through the market created by the PX. These bilateral contracts may either be physical or financial bilaterals. Physical bilaterals involve the scheduling of generation to meet the specific load requirements of end-use customers. Financial

[42]This result of a least-cost dispatch assumes that bidders cannot exercise market power.

bilaterals involve the REP selling power to the PX, the end-use customer purchasing power from the PX, and the REP entering into a CFD with the end-use customer. In a CFD, a generator and buyer agree to a price for electricity. If the MCP exceeds the CFD price, the generator will compensate the buyer for the difference. If the MCP is less than the contract price, the buyer compensates the generator for the difference. If the generator fails to deliver, the PX provides a source of power priced at the MCP for the generator to purchase, fulfilling its obligation under the contract.

Each REP is responsible for providing projections of its customers= load to the ISO for scheduling. Differences between the actual and projected usage are then balanced through the PX. To the extent that a REP provides inaccurate forecasts, it will be subject to the risk of purchasing power on the open spot market through a settlement process. There are no administrative penalties for using the PX for balancing services, only the risks associated with buying from the open spot market.

(3) Distribution Business Unit

Each consumer could choose to have distribution service billed directly to the consumer or to its REP. REPs may provide a single bill to their customers, including energy and delivery charges, provide a bill for the energy component only, or contract with the LDU to provide a single bill which includes both the energy and delivery charges to customers of the REP. If the REP sends the customer a bill for energy and delivery, the LDU will bill the REP for the delivery services. Coordination between the REP and LDU will be required for billing, meter reading and service connections.

The LDU may function as the supplier of last resort by purchasing power from the PX at the established market clearing price. The LDU may also provide power for those customers that opt not to choose an alternative REP. Purchases by the LDU for these customers will enhance the volume of business conducted through the PX, thus increasing the level of liquidity in the PX market. This increase in liquidity should provide for a more competitive price and the development of an active futures market that can be utilized by market participants to manage price risk through hedging.

(4) Customer Service Business Unit

All customers will have a choice of energy provider. Transmission and distribution will be provided under regulated rates. The point of contact for billing-related questions will be handled by the provider of the bill. ALights-out@ calls will be handled by the LDU. Consumers wanting new service can either call the REP or LDU. If metering is not unbundled (open to competition), the LDU will continue to connect and disconnect service under rules established by its regulatory authority. If metering is unbundled, the provider (REP or LDU) would have responsibility for disconnection of service. These rules will also be set by the LDU=s appropriate state or local regulatory authority.

B. POTENTIAL ISSUES

1. Infrastructure Needs.

a) Load Forecasts and Scheduling Generation: The REPs will ultimately be responsible for providing and revising their load forecasts for each LDU=s service territory to the appropriate ISO or individual transmission control areas. However, REPs will need access to information on consumer usage that will allow them to make these load forecasts, and such information must initially be made available from the LDUs having this information. The ISO or individual transmission control areas may need to revise submitted forecasts in such a way that the sum of all REP load forecasts equals the ISO=s or individual control area=s forecast of coincident system load.[43] Also, penalties may need to be established to penalize those REPs who forecast their own load less accurately on average than the ISO or individual transmission control areas. Rules regarding load forecasting and penalties should be addressed either by the ISO or the individual transmission control areas, and in either case will be subject to approval by the appropriate state regulatory authorities and the FERC.

b) Scheduling: The REPs will schedule with the ISO or individual transmission control areas the generation needed to meet their load forecasts for each LDU service territory. Rules regarding scheduling will be addressed by the ISO or

[43] Whether or not there are ISOs, the individual transmission control area will need to make and revise hourly load forecasts for the load located at the points of delivery within its control area. If there are ISOs, the individual transmission control areas would supply their forecasts to the ISO. In addition, the ISO will likely make adjustments to these individual load forecasts in coming up with its aggregate load forecast.

individual transmission control areas, and, in either case, will be subject to approval by the FERC.

c) Ancillary Services: Arrangements will need to be made between the REPs and the various ISOs or individual transmission control areas for the provision of ancillary services. This should be addressed either by the ISO or the individual transmission control areas, and, in either case, will be subject to approval by the FERC.

d) Balancing: Arrangements for generation needed to meet the difference between forecasted hourly loads and actual hourly loads will need to be coordinated between the REPs and the various affected ISOs or individual transmission control areas. Once REPs have prescheduled their deliveries to meet their forecasted loads, the ISO will arrange for the generation needed to meet the difference between forecasted hourly loads and scheduled deliveries. As the hour of operation approaches, the ISO will update REP load forecasts and REPs will modify their preschedules to match their revised forecasted loads. Once the REPs have revised their schedules, the ISO will revise its generation arrangements to meet the difference between the revised load forecasts and revised delivery schedules. Prior to the hour of actual operation, the ISO will also arrange for any generation necessary to perform its moment-to-moment system balancing function. This should be addressed either by the ISO or the individual transmission control areas, and, in either case, will be subject to approval by the FERC.

e) Settlements: A process will need to be set in place for settlements between the REPs and the ISOs or individual transmission control areas for differences between

forecasted and actual hourly usage of electricity. All imbalances are settled by paying or being paid the power exchange market clearing price.

f) Hourly Metering: The size of customer requiring hourly metering needs to be established. Since this is related to the settlements process, it should be addressed by the ISO or the individual transmission control areas, and, in either case, will be subject to approval by the FERC.

g) Data Access for Billing: Many entities will need access to customer data for purposes of forecasting and billing. This issue should be addressed by the relevant state or local regulatory authority, and will likely be subject to approval by the FERC.

2. Certification of Retail Electric Providers. For purposes of assuring adequacy of electricity supply, certification of REPs will need to be addressed. Requirements to be certified as a REP in the state of Missouri should be addressed by the state legislature.

3. Setting Generation Supply Reliability Requirements. The ISO or individual transmission control areas will need to establish the generation supply reliability requirements for the scheduling of generation by the REPs.[44] REPs who fail to deliver supplies to match their forecasted load would be subject to severe penalties. To manage their risk of potential exposure to penalties, REPs will need to manage the reliability of their power supplies. REPs can manage the reliability of their power supplies by performing appropriate maintenance on the generation facilities they own and by specifying reliability requirements in their bilateral contracts with

[44]By the generation supply reliability requirements is meant the availability of generators to provide the electricity when it is needed.

other suppliers. In addition, REPs can either construct or contract in advance for backup supplies. These requirements will be approved by the FERC.

4. Standard Offers. REPs may be required to post standard prices that may differ by customer class/load shape type. These standard offers of service would be available to all individual consumers whose load requirements fit the specific offers of service and who do not want to individually negotiate the prices and terms of service. The Aall takers@ provision could either be applied to REPs statewide or by distribution service territory. The necessity of the standard offer requirement should be determined by the state legislature.

5. Customer Service Unbundling. A significant issue to address is the extent to which the customer service functions will be unbundled. Some states are requiring that metering, meter reading and billing be open to retail competition. Unbundling of the customer service functions adds many new complications to retail competition. If metering is open to competition, some of the issues to be addressed include meter testing, installation procedures, quality and the assignment of responsibility. Competitive billing will require new dispute resolution procedures and disclosure requirements. Other service-related issues include connect, disconnect and storm restoration rules. The decision to unbundle the customer service functions should be left up to the state legislature, while many of the issues related to implementing unbundling are best left up to the LDU=s state or local regulatory authority.

6. Municipals / Cooperatives: Opt In / Opt Out. The state legislature will need to determine whether municipal and/or cooperative electric systems should be allowed the option not to participate in giving their customers direct access to alternative REPs.

7. Affiliate Transaction Rules and Standards of Conducts. Affiliate transaction rules and standards of conduct for transactions between any Generation/REP function of an existing utility and their regulated operation will be needed. The MoPSC and/or state legislature should address this issue.

8. Rules for Bidding Generation. In order to provide a level playing field for all generators and power marketers, rules for bidding generation will need to be established by the Power Exchange. These rules will need to be approved by the FERC.

9. Power Exchange Approval and Oversight. Establishment of the power exchange and its management structure would likely require legislative approval, while governance and operating issues would require regulatory oversight and approval by the FERC.

C. POTENTIAL STRUCTURAL IMPACTS ON UTILITIES

1. Obligation to Serve. With generation open to competition, the existing utilities will no longer have the obligation to plan for and build new generation. Their existing obligation to serve will be redefined as an obligation to connect consumers to the grid and deliver energy at the market price.

2. Company Structure. Generation will be functionally separated from transmission, distribution and customer services. The separate generation business units will need to decide whether they will compete in the market for generation, or sell off their generation assets. Competition in the market for generation could be either at the wholesale or at the retail level.

With transmission separate from generation, the ISO or the individual transmission control areas will need to acquire generation for ancillary services on a competitive basis to

meet the requirements of FERC Orders 888 and 888A. With direct access, the transmission customer should also have the option to acquire ancillary services directly from generators or power marketers.

If customer services such as metering, meter reading and billing are offered on a competitive basis, then this part of the traditional utility business will also need to be functionally separated from the distribution wires service of the LDU.

3. Standards of Conduct. Functional separation by way of a code of conduct will, at a minimum, need to be in place between the competitive and non-competitive functions of the utilities. This code of conduct will most likely be set by the MoPSC for the investor-owned utilities. The state legislature will need to decide how the code will be set for Municipal and Cooperative utilities.

4. Rate and Bill Unbundling.

a) Distribution Rates: Separate rates for distribution service from the LDU will be required. These rates will be set by the relevant state or local regulatory authorities.

b) Transmission Rates: If there is an ISO, charges for transmission will be at the ISO rate, rather than at a separate LDU transmission rate. If the LDU is not a member of an ISO, then that LDU=s individual control area transmission rate will be applied. Both the ISO rate and the individual transmission control area rate will be set by the FERC.

c) Regulated Generation Rates: If the LDU would continue to provide generation on a regulated basis, then this service would need to be set out as a separate rate.

Rates for regulated generation will be set by the relevant state or local regulatory authority.

d) Regulated Customer Service Rates: If customer services such as metering, meter reading and billing are offered on a competitive basis and the LDU continues to provide these services on a regulated basis, then the LDU=s regulated charges for these services will also need to be separate. Rates for regulated customer services will be set by the relevant state or local regulatory authority.

e) Separate Charges on Customer=s Bill: While customers will have the option of paying a single bill, that bill will need to show the separate charges for each component of service.

5. Upgrades to Customer Information Systems. Utility customer information systems (CIS) will most likely require extensive upgrades to track:

- **$** Who the REP is for each customer;
- **$** Who bills for each service;
- **$** Who owns the metering equipment (if metering is competitively provided);
- **$** Who reads the meter (if meter reading is competitively provided);
- **$** What data must be transferred to the ISO, REPs, etc.;
- **$** Rates for alternative REPs (if billing is contracted to the LDU);
- **$** Hourly usage data for larger customers; and
- **$** Hourly profile data for smaller customers.

6. Anti Flip-Flop Laws. The current state law does not allow utilities to compete for existing customers of another utility based on price. In order to implement direct access, this law would need to be rescinded.

D. POTENTIAL IMPACTS ON CONSUMERS

1. Generation Service Options. Consumers will be given the opportunity to choose their electricity provider. Consumer alternatives may include

- **$** Aggregators
- **$** LDU
- **$** PX
- **$** Other Alternative REPs

2. Metering and Billing Options. Consumers may have a choice of alternative providers for metering and/or billing services. With these choices, consumers could receive a single bill from either the REP or LDU, or could elect to receive separate bills, one for electricity from the REP and one for delivery services from the LDU.

3. Consumer Education. With new choices for generation, and possibly metering and billing, consumer education will be necessary. Possible sources of consumer education would include the MoPSC, the OPC, the LDUs and the REPs. Consumer education should focus on the ways that consumers can elect to obtain electricity and the procedures that consumers need to follow to implement their choices.

4. Sales Practices. Any REP licensed by the state to offer electricity for sale at retail could be required to include with every sales offer a MoPSC-approved Standard Cost Comparison Disclosure form. The Standard Cost Comparison Disclosure would require that REPs uniformly and accurately disclose the true cost, term, conditions, disclaimers and reliability of the service they are offering. The state may also want to assert MoPSC oversight of REP advertisements and sales promotion material to minimize misleading or false claims of price and/or expected savings to the consumer.

5. Generation Reliability. With the competitive supply of generation, end-use consumers may see a different level of generation reliability than exists under the current system.[45] In addition, a variety of interruptible service options for accepting different levels of generation reliability may be made available to end-use consumers by the REPs.

6. Provider of Last Resort. The LDU will serve high-risk/high-cost consumers. The LDU will purchase power from the competitively bid PX to supply these customers. The LDU would be compensated for its costs incurred for bad debt associated with serving high risk/high cost consumers.

7. Assignment of Default Customers. Default customers are those consumers that choose not to choose any particular REP as their service provider. The LDU will purchase power from the competitively bid PX to supply these customers. The cost of this power will then be passed on to these consumers through a single LDU bill.

8. Privacy of Consumer Information. There will be a need for REPs to have historical usage information on the specific consumers to whom they will provide electricity. This information will be provided by the LDU serving the consumer only upon first receiving the permission of the consumer.

[45]The current system relies on designed levels of planning reserves for generation to ensure reliability.

APPENDIX
FERC ORDER 888 ISO CRITERIA

1. **The ISO=s governance should be structured in a fair and non-discriminatory manner.**
The primary purpose of an ISO is to ensure fair and non-discriminatory access to transmission services and ancillary services for all users of the system. As such, an ISO should be independent of any individual market participant or any one class of participants (e.g., transmission owners or end-users). A governance structure that includes fair representation of all types of users of the system would help ensure that the ISO formulates policies, operates the system, and resolves disputes in a fair and non-discriminatory manner. The ISO=s rules of governance, however, should prevent control, and appearance of control, of decision-making by any class of participants.

2. **An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.**
To be independent, an ISO cannot be owned by any market participant. We recognize that transmission owners need to be able to hold the ISO accountable in its fiduciary role, but should not be able to dictate day-to-day operational matters. Employees of the ISO should also be financially independent of market participants. We recognize, however, that a short transition period (we believe 6 months would be adequate) will be needed for employees of a newly formed ISO to sever all ties with former transmission owners and to make appropriate arrangements for pension plans, health programs and so on. In addition, an ISO should not undertake any contractual arrangement with generation or transmission owners or transmission users that is not at arm=s length. In order to ensure independence, a strict conflict of interest standard should be adopted and enforced.

3. **An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.**
An ISO should be responsible for ensuring that all users have non-discriminatory access to the transmission system and all services under ISO control. The portion of the transmission grid operated by a single ISO should be as large as possible, consistent with the agreement of market participants, and the ISO should schedule all transmission on the portion of the grid it controls. An ISO should have clear tariffs for services that neither favor nor disfavor any users or class of users.

4. **An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.**
Reliability and security of the transmission system are critical functions for a system operator. As part of this responsibility an ISO should oversee all maintenance of the transmission

facilities under its control, including any day-to-day maintenance contracted to be performed by others. An ISO may also have a role with respect to reliability planning. In any case, the ISO should be responsible for ensuring that services (for all users, including new users) can be provided reliably, and for developing and implementing policies related to curtailment to ensure the on-going reliability and security of the system.

5. **An ISO should have control over the operation of interconnected transmission facilities within its region.**
An ISO is an operator of a designated set of transmission facilities.

6. **An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.**
A key function of an ISO will be to accommodate transactions made in a free and competitive market while remaining at arm=s length from those transactions. The ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system, especially when transmission constraints limit trading over interfaces in some circumstances. It is important that the ISO=s operational control be exercised in accordance with the trading rules established by the governing body. The trading rules should promote efficiency in the marketplace. In addition, we would expect that an ISO would provide, or cause to be provided, the ancillary services described in this Rule.

7. **The ISO should have appropriate incentives for efficient management and administration and should procure the services for such management and administration in an open competitive market.**
Management and administration of the ISO should be carried out in an efficient manner. In addition to personnel and administrative functions, an ISO could perform certain operational functions, such as: determination of appropriate system expansion, transmission maintenance, administering transmission contracts, operation of a settlement system, and operation of an energy auction. The ISO should use competitive procurement, to the extent possible, for all services provided by the ISO that are needed to operate the system. All procedures and protocols should be publicly available.

8. **An ISO=s transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.**
Appropriate price signals are essential to achieve efficient investment in generation and transmission and consumption of energy. The pricing policies pursued by the ISO should reflect a number of attributes, including affording non-discriminatory access to services, ensuring cost recovery for transmission owners and those providing ancillary services, ensuring reliability and stability of the system and providing efficient price signals of the costs of using the transmission grid. In particular, the Commission would consider transmission pricing proposals for

addressing network congestion that are consistent with our Transmission Pricing Policy Statement. In addition, an ISO should conduct such studies and coordinate with market participants including RTGs, as may be necessary to identify transmission constraints on its system, loop flow impacts between its system and neighboring systems, and other factors that might affect system operation or expansion.

9. **An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission=s requirements.** A free-flow of information between the ISO and market participants is required for an ISO to perform its functions and for market participants to efficiently participate in the market. At a minimum, information on system operation, conditions, available capacity and constraints, and all contracts or other service arrangements of the ISO should be made publicly available. This information should be made available on an OASIS operated by the ISO.

10. **An ISO should develop mechanisms to coordinate with neighboring control areas.** An ISO will be required to coordinate power scheduling with other entities operating transmission systems. Such coordination is necessary to ensure provision of transmission services that cross system boundaries and to ensure reliability and stability of the systems. The mechanisms by which ISOs and other transmission operators coordinate can be left to those parties to determine.

11. **An ISO should establish and ADR process to resolve disputes in the first instance.** An ISO should provide for a voluntary dispute resolution process that allows parties to resolve technical, financial, and other issues without resort to filing complaints at the Commission. We would encourage the ISO to establish rules and procedures to implement alternative dispute resolution processes.